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Golder Associates

AIR PERMIT APPLICATION AND PREVENTION OF SIGNIFICANT DETERIORATION ANALYSIS FOR THE SHADY HILLS GENERATING STATION

Prepared for:

Shady Hills Power Company, LLC
c/o GE Energy Financial Services
120 Long Ridge Road
Stamford, Connecticut 06927

Prepared by:

Golder Associates Inc.
5100 West Lemon Street, Suite 114
Tampa, Florida 33609

Distribution:
4 Copies – Florida Department of Environmental Protection
2 Copies – GE Energy Financial Services
2 Copies – Golder Associates Inc.

May 2008 083-89507

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Scott H. Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**53304** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **SOsbourn@golder.com**
5.	Professional Engineer Statement:

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

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

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

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

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

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

Signature _____________ Date 5/9/08

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

*** Attach any exception to certification statement.**
**** Board of Professional Engineers Certificate of Authorization # 00001670**

Golder Associates Inc.
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Golder Associates

May 12, 2008

RECEIVED
MAY 13 2008
BUREAU OF AIR REGULATION

Mr. Jonathan Holtom
Florida Department of Environmental Protection
North Permitting Section
Division of Air Resource Management
2600 Blair Stone Road MS 5000
Tallahassee, Florida 32399-2400

Re: Shady Hills Generating Station
PSD Air Permit Application for Site Expansion
Facility ID No. 1010373

Dear Mr. Holtom:

Please find enclosed an original and three copies of the PSD air construction permit application, as well as a check for $7,500, for a proposed plant expansion at the above-referenced facility. This application is consistent with the project scope we had discussed during our pre-application meeting in your offices on April 9, 2008.

Thank you in advance for your timely processing of this permit request. If you should have any questions, please don't hesitate to contact either myself at (813) 287-1717 or Roy Belden of GE Energy Financial Services at (203) 357-6820.

Sincerely,

Scott Osbourn, P.E.
Senior Consultant

Enclosures

cc: Roy Belden, GE Energy Financial Services
William Stevens, GE Energy Financial Services
Rick Waggoner, Compliance Opportunities Group

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1.0 INTRODUCTION

The Shady Hills Power Company, LLC (Shady Hills), a subsidiary of GE Energy Financial Services owns and operates the Shady Hills Generating Station located at 14240 Merchant Energy Way, Shady Hills, Pasco County, Florida. This facility consists of three, dual-fuel, nominal 170 megawatt (MW) General Electric model PG7241FA (GE 7FA) simple cycle combustion turbine-electric generators, three 75-foot exhaust stacks, and one 2.8 million gallon fuel oil storage tank.

Shady Hills proposes to license, construct, and operate two additional new simple-cycle units at the Shady Hills Generating Station (the "Project"), in unincorporated Pasco County, Florida (Figure 1-1). The Project consists of the addition of two simple cycle GE 7FA combustion turbines (CTs), emission Units 005 and 006, that will use dry low-nitrogen oxide (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 combustion turbines will be natural gas with distillate fuel oil used as backup fuel. Fuel oil will contain a maximum ultra-low sulfur content of 0.0015 percent.

The Project will require an additional gas heater for the two new CTs. The present heater at the facility is only sized for the existing three GE7FA CTs. In addition, since the present generator is marginally rated, there will be a need to increase the size of the emergency diesel/generator to accommodate the additional CTs.

The Project requires an air construction permit and prevention of significant deterioration (PSD) review. To assist in performing the necessary licensing activities Shady Hills 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 Project will be a major modification to an existing air pollution source that will result in increases in air emissions in Pasco County. The U.S. Environmental Protection Agency (EPA) has implemented regulations requiring a PSD review. PSD regulations are promulgated under 40 Code of Federal Regulations (CFR) Part 52.21 and implemented through the Florida Department of

Environmental Protection's (DEP) SIP-approved program. Florida's PSD regulations are codified in Rules 62-212.400, F.A.C. These regulations incorporate the EPA PSD regulations.

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

- 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), 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 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 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.

0 25 50 100
Miles
1 inch equals 400,000 feet

N

REFERENCES

1. County boundaries - Florida Department of Environmental Protection

PROJECT
SHADY HILLS POWER COMPANY
PASCO COUNTY, FLORIDA

TITLE
GENERAL SITE LOCATION MAP

Golder Associates
Tampa, Florida

PROJECT No. 083-89507			SCALE AS SHOWN	REV. 0
DESIGN	PB	03/30/08	**FIGURE 1-1**	
GIS	PB	03/30/08		
CHECK	KE	03/30/08		
REVIEW	KE	03/30/08		

073-89524A001 - Figure 1-1 Project Vicinity Aerial.mxd

2.0 PROJECT DESCRIPTION

2.1 Site Description

The project site, Shady Hills Generating Station, is shown in Figure 2-1. There is minimal industrial and commercial development within a three 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 is supplied to the site by a lateral pipeline connected to the Florida Gas Transmission (FGT) natural gas pipeline located west of the site. The site has access to transmission facilities from a 230-kV transmission line and electrical substation that is located to the west of the site. Water for the Project, including NO_x control when firing oil, will be supplied by onsite groundwater wells. Potable water and additional fire protection supply water will be provided from groundwater wells.

2.2 Power Plant

The project will consist of two General Electric Frame 7FA CTs (GE 7FA) and associated facilities. The GE 7FA units will each be equipped with evaporative cooling. The annual maximum capacity factor of the plant will be 39 percent, which is equivalent to operating 3,390 hours/year at full load per CT. 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/year at full load per CT. No single combustion turbine will operate more than 5,000 hours in a single year. The project will require an additional gas heater for the two new CTs. In addition, since the present generator is marginally rated, there will be a need to increase the size of the emergency diesel/generator to 2,250 kW to accommodate the additional CTs.

Plant performance for each of the CTs under consideration for the Project was developed for natural gas and oil-firing at 100 percent and lower operating loads and turbine inlet temperatures of 20°F, 59°F, and 95°F. Nominal part load information is presented in Appendix A. 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, Shady Hills 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 0.0015 percent, will be stored onsite in one new 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 dry low-NO_x (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 radially 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, 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 CTs operating at baseload conditions (100-percent load), 75-percent load, and 50-percent load conditions are presented in Tables 2-1 and 2-2. 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 20°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 listed in Appendix A.

The proposed 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% O_2	9	42
CO, ppmvd	9	20
VOC as CH_4, ppmvd (gas), ppmvw (oil)	1.6	4
SO_x as SO_2	Calculated Based on Fuel (2.0 grains S/100 SCF)	Calculated Based on Fuel (0.0015% sulfur)
PM_{10} lb/hr (dry filterable)	9	17

The maximum short-term emission rates (lb/hr) generally occur at baseload, 20°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 2-3 for 1 and 2 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 20°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 20°F are presented in Figure 2-2 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. Since 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 nine scenarios which are designed to determine the maximum impacts for the project:

- Base operating load for the turbine at an inlet temperature of 20°F;

- Base operating load for the turbine at an inlet temperature of 59°F;
- Base operating load for the turbine at an inlet temperature of 95°F;
- A 75-percent operating load for the turbine at an inlet temperature of 20°F;
- A 75-percent operating load for the turbine at an inlet temperature of 59°F;
- A 75-percent 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 20°F;
- A 50-percent operating load for the turbine at an inlet temperature of 59°F; and
- A 50-percent operating load for the turbine at an inlet temperature of 95°F.

The estimated maximum hourly emissions and exhaust information representative of the proposed emergency generator and natural gas heater are presented in Tables 2-4 and 2-5, respectively. The natural gas heater will utilize a heat transfer fluid for heating the natural gas and be fired with only natural gas. The heater will have an estimated heat input of 10 MMBtu/hr or less. This heater will be used as necessary to heat natural gas above the dew point. The emergency generators would be typically operated one to two hours per month for maintenance and reliability testing.

A summary of the maximum total potential annual emissions estimated for the project is given in Table 2-6.

EPA's interim guidance indicates that PM_{10} can be used as a surrogate for until such time as $PM_{2.5}$ guidance is promulgated. Therefore, the emissions of $PM_{2.5}$ for the CTs and gas heater are equivalent to emission of PM_{10}. For the emergency generator, $PM_{2.5}$ emissions were developed from $PM_{2.5}$ emission factors available from EPA AP-42 *Compilation of Air Pollutant Emission Factors.*

Emergency Generator – $PM_{2.5}$: 0.0566 pounds per million British thermal units (lb/MMBtu); 1.2 lb/hr and 0.29 TPY.

Emission factors for hazardous air pollutants (HAPs) were evaluated based on the revised AP-42 emission factors, the EPA Combustion Turbine Emissions Database and the combustion turbine Maximum Achievable Control Technology (MACT) standards. The HAP emissions are based on emission factors from the April 2000 revision of EPA's AP-42 emission factors for large stationary combustion turbines. Summaries of the emission factors and emissions for light oil firing and gas firing are presented in Appendix A.

The MACT standard in 40 CFR, Subpart YYYY is potentially applicable to the Project. However, Shady Hills Generating Station will not be a major source of HAP emissions since emissions are projected to be below 10 tons per year (TPY) of a single HAP and less than 25 TPY for all HAPs.

An emission factor for toluene of 33 lb/10^{12} Btu, for natural gas firing, was developed from the data in the EPA Combustion Turbine Emissions Database. This factor is based on the median value for loads greater than 80 percent. Similar to formaldehyde emission factors, there are no confirmed test data of toluene emissions from F Class turbines. The recent EPA emission factor, which is based on much smaller turbines than those proposed for the project, suggests toluene emissions from gas turbines of 130 lb/10^{12} Btu when firing natural gas at loads greater than 80 percent. For all loads, the average and median EPA factors are 94 and 19 lb/10^{12} Btu, respectively. Since the median emission factor is about four to five times lower than the average factor, this clearly points to the large range in toluene emissions and how the individual turbine combustion characteristics can influence the results.

The emission factors for many of the other HAPs were developed by EPA in a manner similar to toluene. For these HAPs, fewer data are available and are also considered not representative of state-of-the-art DLN combustion systems. The use of AP-42 emission factors for HAPs is considered to provide conservative estimates of emissions.

The emergency generator is potentially subject to 40 CFR 63 Subpart ZZZZ, the Reciprocating Internal Combustion Engine (RICE) MACT Rule. However, Shady Hills Generating Station will remain a minor source of HAP emissions. If Subpart ZZZZ becomes applicable, the emergency generators will only be subject to the notification requirements of the RICE MACT (i.e., no emissions limitations will apply) since it would qualify for one of the following rule exemptions:

- Emergency Generator - Any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, or stationary RICE used to pump water in case of fire or flood, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of the emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

- Limited Use - Any stationary RICE that operates less than 100 hours per year.

Note that the estimated emissions provided a worst-case estimate for determining PSD applicability and are not representative of normal operation. For maintenance and reliability testing, the emergency generator will normally be operated about 1 to 2 hours per month or approximately 12 to 24 hr/yr.

The National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, 40 CFR Part 63, Subpart DDDDD is applicable to industrial, commercial, or institutional boilers or process heaters. Subpart DDDDD defines boiler and process heaters as follows in 40 CFR 63.7575:

> *"Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Waste heat boilers are excluded from this definition."*
>
> *"Process heater means an enclosed device using controlled flame, that is not a boiler, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to heat transfer material for use in a process material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not directly come into contact with process materials. Process heaters do not include units for comfort heat or space heat, food preparation for on-site consumption, or autoclaves."*

The Project will include one 10 MMBtu/hr indirect process heater for the purpose of heating the natural gas supply to the CTs. However, as stated previously, Shady Hills Generating Station will not be a major source of HAPs as a result of the Project and as such will not be subject to Subpart DDDDD.

2.4 Site Layout, Structures, and Stack Sampling Facilities

A plot plan of the proposed facility is presented in Figure 2-3. 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.

2.5 Excess Emissions

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest."

Steady operation of the General Electric Frame 7FA combustion turbine is achieved at least by 50% of base load conditions. Simple cycle gas turbines are designed for quick startup and operate at high load levels. Operation of the large frame gas turbines is generally automated and malfunctions have been infrequent.

Dry Low NO_X combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions.

TABLE 2-1
STACK, OPERATING, AND EMISSION DATA FOR THE COMBUSTION TURBINES FOR SIMPLE CYCLE OPERATION - NATURAL GAS COMBUSTION

		Operating and Emission Data[a] for Ambient Temperature		
		Combustion Turbine		
Parameter		20 °F	59 °F	95 °F
CT Stack Data (ft)				
Height		75	75	75
Diameter		18.0	18.0	18.0
100 Percent Load				
		1,074	1,113	1,154
Velocity (ft/sec)		168.7	161.3	152.0
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	11.2	10.4	9.5
PM/PM_{10}	lb/hr	9.0	9.0	9.0
NO_x	lb/hr	63.6	59.4	53.8
CO	lb/hr	32.1	29.7	26.8
VOC (as methane)	lb/hr	3.3	3.0	2.7
Sulfuric Acid Mist	lb/hr	1.7	1.6	1.5
75 Percent Load				
		1,200	1,159	1,190
Velocity (ft/sec)		137.5	133.6	128.7
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	9.2	8.5	7.9
PM/PM_{10}	lb/hr	9.0	9.0	9.0
NO_x	lb/hr	51.7	47.8	44.1
CO	lb/hr	24.1	23.9	22.2
VOC (as methane)	lb/hr	2.4	2.4	2.3
Sulfuric Acid Mist	lb/hr	1.41	1.30	1.20
50 Percent Load				
		1,200	1,200	1,200
Velocity (ft/sec)		116.0	113.3	108.9
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	7.3	6.8	6.3
PM/PM_{10}	lb/hr	9.0	9.0	9.0
NO_x	lb/hr	40.3	37.8	34.8
CO	lb/hr	20.4	19.9	18.8
VOC (as methane)	lb/hr	2.1	2.0	1.9
Sulfuric Acid Mist	lb/hr	1.11	1.04	0.96

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE 2-2
STACK, OPERATING, AND EMISSION DATA FOR THE COMBUSTION TURBINES FOR SIMPLE CYCLE OPERATION - ULTRA LOW-SULFUR LIGHT OIL COMBUSTION

		Operating and Emission Data[a] for Ambient Temperature Combustion Turbine		
Parameter		20 °F	59 °F	95 °F
CT/HRSG Stack Data (ft)				
Height		75	75	75
Diameter		18	18	18
100 Percent Load				
		1,053	1,093	1,143
Velocity (ft/sec)		172.4	164.7	154.8
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	3.3	3.1	2.8
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	345.9	322.3	293.5
CO	lb/hr	71.1	66.2	60.5
VOC (as methane)	lb/hr	8.2	7.5	6.7
Lead	lb/hr	0.028	0.026	0.024
Sulfuric Acid Mist	lb/hr	0.50	0.47	0.43
75 Percent Load				
		1,196	1,200	1,200
Velocity (ft/sec)		139.4	135.6	130.7
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	2.7	2.5	2.3
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	280.4	263.3	239.2
CO	lb/hr	52.2	50.6	48.3
VOC (as methane)	lb/hr	6.0	5.8	5.5
Lead	lb/hr	0.023	0.022	0.020
Sulfuric Acid Mist	lb/hr	0.41	0.39	0.35
50 Percent Load				
		1,196	1,200	1,200
Velocity (ft/sec)		116.0	114.5	110.2
Maximum Hourly Emissions per Unit				
SO_2	lb/hr	2.1	2.0	1.8
PM/PM_{10}	lb/hr	17.0	17.0	17.0
NO_x	lb/hr	214.9	203.6	185.2
CO	lb/hr	44.2	43.4	41.3
VOC (as methane)	lb/hr	5.0	5.0	4.7
Lead	lb/hr	0.018	0.017	0.015
Sulfuric Acid Mist	lb/hr	0.32	0.30	0.28

[a] Refer to Appendix A for detailed information on basis of pollutant emission rates and operating data.
Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE 2-3

SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE CTS IN SIMPLE CYCLE OPERATIONS

		Maximum Hourly Emissions (lb/hr)[a]		Maximum Emissions (tons/year)		
		Simple Cycle (SC)		Operating Scenario	Operating Hours	
	Fuel:	NG	Oil	SC/ NG 100 % Load	3,390	2,390
	Temp & Load:	59 °F, 100%	59 °F, 100%	SC/ OIL 100 % Load	0	1,000
Pollutant				TOTAL	3,390	3,390
One Combustion Turbine						
SO_2		10.4	3.1		17.7	14.0
PM/PM_{10}		9.0	17.0		15.3	19.3
NO_x		59.4	322.3		100.7	232.1
CO		29.7	66.2		50.3	68.6
VOC (as methane)		3.0	7.5		5.1	7.4
Sulfuric Acid Mist		1.6	0.5		2.7	2.1
HAPs		0.81	2.47		1.4	2.2
Lead		0.00	0.026		0.0	0.013
Two Combustion Turbines						
SO_2		20.9	6.2		35.4	28.0
PM/PM_{10}		18.0	34.0		30.5	38.5
NO_x		118.8	644.5		201.3	464.2
CO		59.4	132.5		100.7	137.2
VOC (as methane)		6.0	15.1		10.2	14.8
Sulfuric Acid Mist		3.2	0.9		5.4	4.3
HAPs		1.6	4.9		2.7	4.4
Lead		0.0	0.1		0.0	0.026

[a] Based on 59 °F ambient inlet air temperature
Source: GE, 2007- CT Performance Data; Golder, 2008

TABLE 2-4

PERFORMANCE AND EMISSION DATA FOR ONE EMERGENCY GENERATOR FOR SHADY HILLS GENERATING STATION PROJECT

Parameter		Emergency Generator
Performance		
Number of Units		1
Rating (kW)		2,500
Rating (hp)		3,200
Fuel		Diesel
Fuel Heat content (Btu/lb) (HHV)		19,300
Fuel density (lb/gal)		7.0
Heat input (MMBtu/hr) (HHV)		21.01
Fuel usage (gallons/hr)		155.5
Maximum operation (hours)		500
Maximum fuel usage (gallons/yr)		77,750
Emissions		
SO_2 -	Basis (%S)	0.0015%
	Conversion of S to SO_2	100
	Molecular weight SO_2/ S (64/32)	2
	Emission rate (lb/hr)	0.03
	(tpy)	0.01
NO_x -	Basis (g/hp-hr)	3.8
	Emission rate (lb/hr)	26.6
	(tpy)	6.65
CO -	Basis (g/hp-hr)	2.6
	Emission rate (lb/hr)	18.4
	(tpy)	4.60
VOC -	Basis (g/hp-hr)	1.0
	Emission rate (lb/hr)	7.1
	(tpy)	1.76
PM/PM_{10} -	Basis (g/hp-hr)	0.075
	Emission rate (lb/hr)	0.53
	(tpy)	0.13

Sources: 40 CFR 60 Subpart IIII, Standards for Stationary Compression Ignition Internal Combustion Engines, Golder, 2008.

TABLE 2-5
PERFORMANCE, STACK PARAMETERS, AND EMISSIONS FOR ONE NATURAL GAS FUEL HEATER, SHADY HILLS GENERATING STATION PROJECT

	Natural Gas Heater
Performance[a]	
Fuel Usage (scf/hr-gas)	9,479
Heat Input (MMBtu/hr-HHV)	10.00
Hours per Year	3,390
Maximum Fuel Usage (MMscf/yr)	83.03
Number of Units	1
Stack Parameters (typical)	
Diameter (ft)	1
Height (ft)	30
Temperature (°F)	500
Velocity (ft/sec)	53
Flow (acfm)	4,950
Emissions	
SO_2 -Basis (grains S/100 scf-gas)[b]	2
(lb/hr)	0.054
(lb/MMBtu)	0.005
(tpy) - one unit	0.237
NO_x - (lb/MMscf)[c]	100
(lb/hr)	0.95
(lb/MMBtu)	0.095
(tpy)	4.2
CO - (lb/MMscf)[c]	84
(lb/hr)	0.80
(lb/MMBtu)	0.080
(tpy)	3.49
VOC - (lb/MMscf)[c]	5.5
(lb/hr)	0.05
(lb/MMBtu)	0.005
(tpy)	0.228
PM/PM10 - (lb/MMscf)[d]	1.9
(lb/hr)	0.02
(lb/MMBtu)	0.002
(tpy)	0.079

[a] Based on 10 MMBtu/hr (HHV) indirect gas heaters from Hanover Compression Company or equivalent.

[b] Typical maximum for natural gas.

[c] EPA, AP-42 Table 1.4-1 using small boilers < 100 MMBtu.hr and Table 1.4-2.

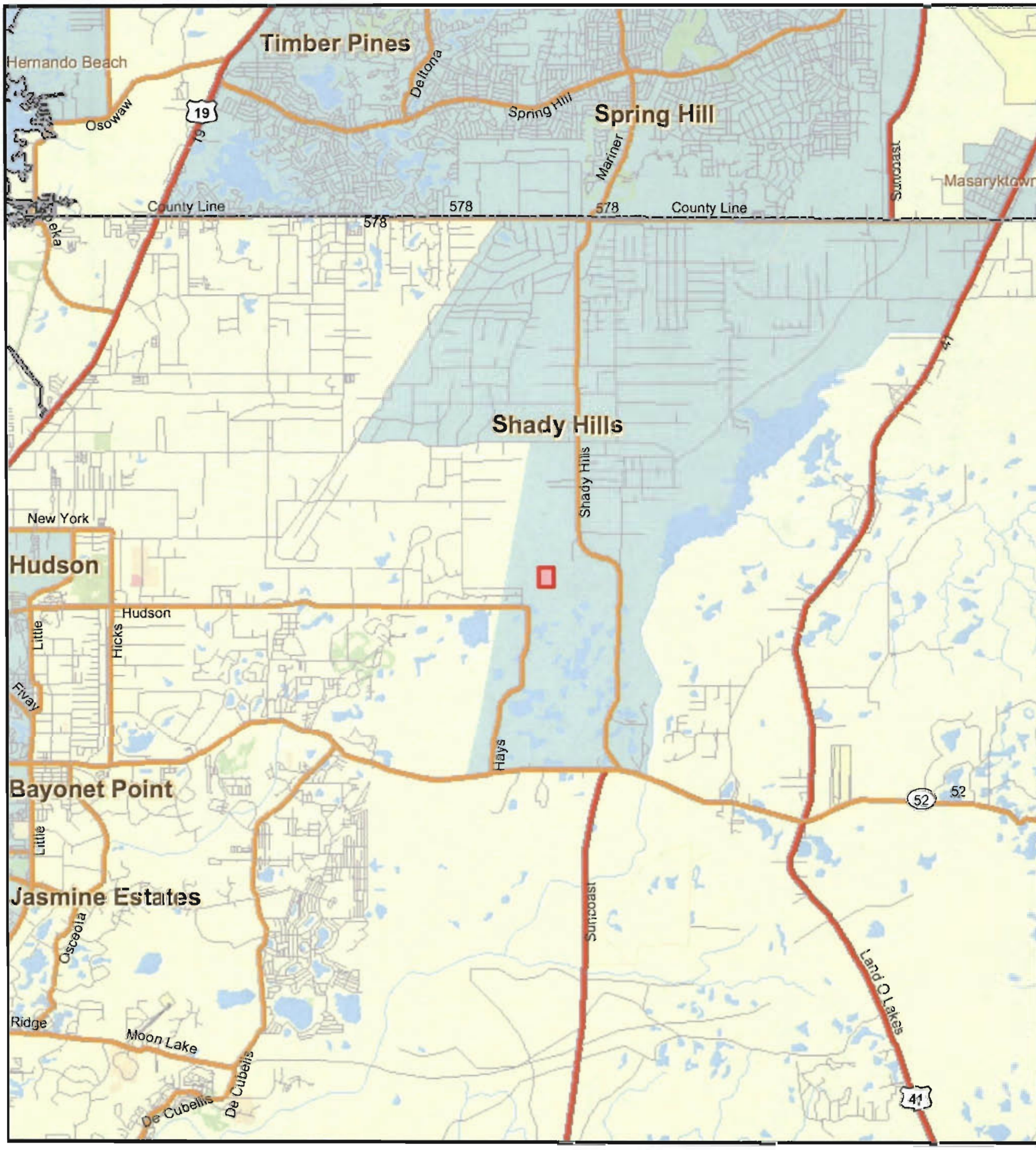
[d] EPA, AP-42 Table 1.4-2 Filterable PM.

TABLE 2-6

SUMMARY OF MAXIMUM POTENTIAL ANNUAL EMISSIONS FOR THE SHADY HILLS GENERATING STATION PROJECT

Pollutant	Annual Emissions (tons/year) 2 CTs	Emergency Generator	Natural Gas Heater	TOTAL	PSD Significant Emission Rate (tons/year)	PSD Review Required?
SO_2	35.4	0.0082	0.24	36	40	No
PM	38.5	0.13	0.08	39	25	Yes
PM_{10}	38.5	0.13	0.08	39	15	Yes
NO_x	464.2	6.65	4.15	475	40	Yes
CO	137.2	4.60	3.49	145	100	Yes
VOC (as methane)	14.8	1.76	0.23	17	40	No
Sulfuric Acid Mist	5.4	NA	NA	5.42	7	No
Lead	0.026	NA	NA	0.03	0.6	No

Source: Golder, 2008.



LEGEND

Shady Hills Property

0 5,000 10,000 20,000 Feet

1 inch equals 10,000 feet

N

REFERENCES

1. County boundaries - Florida Department of Environmental Protection
2. Roads & Railroads - ESRI StreetMap

PROJECT

SHADY HILLS POWER COMPANY
PASCO COUNTY, FLORIDA

TITLE

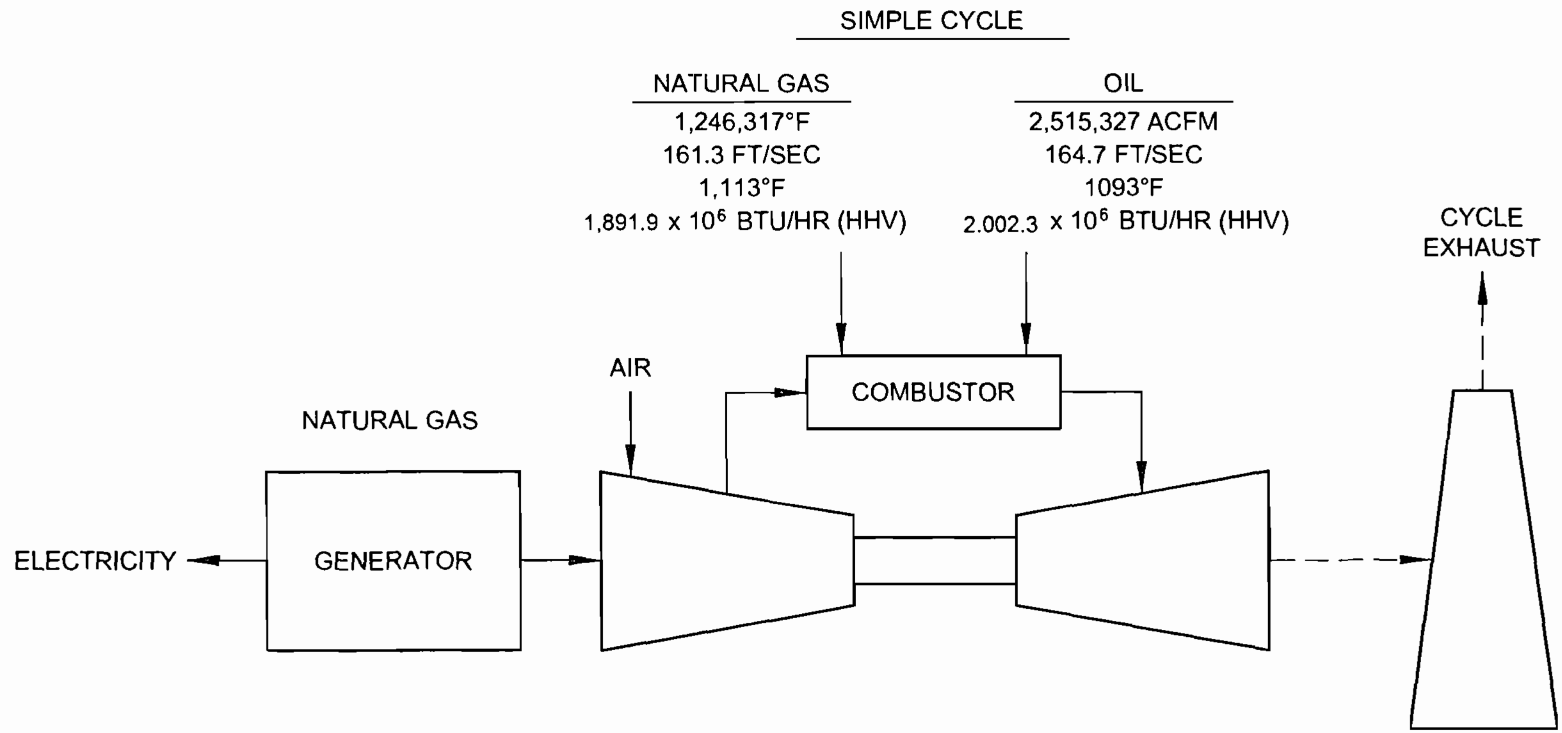
PROJECT LOCATION MAP

Golder Associates
Tampa, Florida

PROJECT No. 083-89507			SCALE AS SHOWN	REV. 0
DESIGN	PB	03/30/08	**FIGURE 2-1**	
GIS	GB	03/30/08		
CHECK	KE	03/30/08		
REVIEW	KE	03/30/08		

073-89524A001 - Figure 1-1 Project Vicinity Aerial.mxd

BASELOAD OPERATION AMBIENT
TEMPERATURE OF 59°F



LEGEND

- SOLID/LIQUID
- GAS

PROJECT
SHADY HILLS POWER COMPANY
PASCO COUNTY, FLORIDA

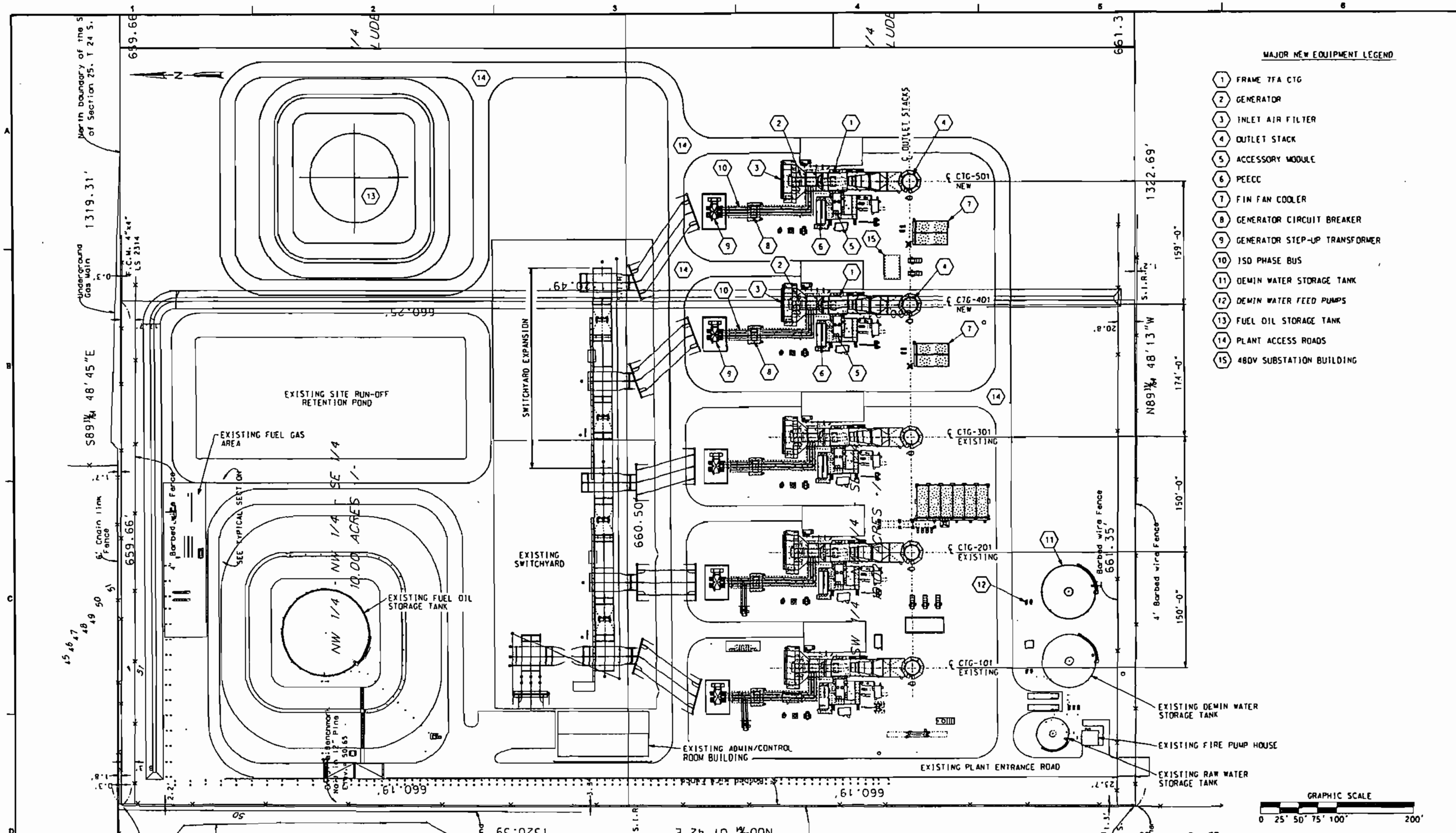
TITLE
**PROCESS FLOW DIAGRAM
BASELOAD OPERATION, AMBIENT
TEMPERATURE OF 59°F**

Golder Associates
Tampa, Florida

PROJECT No.		083-89507	FILE No.	083-89507A001
DESIGN	DL	03/25/08	SCALE AS SHOWN	REV. 0
CADD	PB	03/25/08		
CHECK				
REVIEW				

FIGURE 2-2

Drawing file: 083-89507A001 Process Flow Diagram.dwg Apr 01, 2008 - 6:01pm



NO.	DATE	REVISION	BY	CHK
P1	03/03/08	ISSUED FOR REVIEW	TBJ	

RESPONSIBLE ENGINEER

REVISION APPROVAL — REV P1 — DATE 03/03/08

DISCIPLINE	REVIEWED	DISCIPLINE	REVIEWED
CIVIL		ELECTRICAL	
STRUCTURAL		INST & CONTROL	
MECHANICAL		ARCHITECTURAL	
PROCESS		ENVIRONMENTAL	
PIPING		GEN. ARRANG.	

PRINT DISTRIBUTION: DATE, STATUS, REV., CLIENT, FIELD, INTRA CO.

STATUS	REV	DATE	DM	SDE	PEM
ISSUED					
PRELIMINARY	P1	03/03/08			
FOR REVIEW AND APPROVAL					
APPROVED FOR CONSTRUCTION					
REVISED & APPROVED FOR CONSTRUCTION					

SCALE 1"=60'-0"

SHADY HILLS
POWER PLANT EXPANSION
Pasco County, FL

PROJECT NO. 370893

CH2MHILL

FIGURE 2-3
7FA SIMPLE CYCLE EXPANSION
SITE PLAN

DWG. NO. SH-GA-SC-00-01 REV. P1

FILENAME: PLOT DATE: PLOT TIME:

BAR IS ONE INCH ON ORIGINAL DRAWING. 0 1"

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 project.

3.1 National, State, and Local 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 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..

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 source 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 that 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). FDEP utilizes the "top-down" BACT approach.

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 to address 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 above significance levels, as presented in Table 3-1.

The EPA has proposed significant impact levels for Class I areas. The levels 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 reviews, 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 to assist states in implementing the PSD permit process. The FDEP has accepted the use of these significant impact levels.

Various lengths of meteorological data records can be used for impact analysis. A five-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (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 five 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, will 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 SO_2 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 SO_2 and PM (TSP) and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM (TSP) has been set as December 27, 1977, for the entire State of Florida (Rules 62-204.200(22); 204.360, F.A.C.). The minor source baseline for NO_2 has been set as March 28, 1988 (Rule 62-204.200(22); 204.360, 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 (Table 3-2).

Ambient air monitoring for a period of up to one year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of four 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.). If the facility's predicted impacts are less than the *de minimis* levels, then preconstruction monitoring is not required.

3.2.5 Source Information/GEP Stack Height

Source information must be provided to adequately describe the 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 meters (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).

3.2.7 Air Quality Related Values

An Air Quality Related Value (AQRV) analysis was conducted to assess the potential risk to AQRVs at the Chassahowitzka NWA due to the proposed emissions from the project generating Facility. The Chassahowitzka NWA is the closest Class I area to the site, and is located approximately 28 km northwest of the project.

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).

The AQRVs include visibility, freshwater and coastal wetlands, dominant plant communities, unique and rare plant communities, soils and associated periphyton, and the wildlife dependent on these communities for habitat. Rare, endemic, threatened, and endangered species of the national park and bioindicators of air pollution (e.g., lichens) must also be evaluated.

3.3 Nonattainment Rules

FDEP has nonattainment provisions (Rule 62-212.500, F.A.C.) that apply to all major new facilities located in a nonattainment area. In addition, for major facilities that are located 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 Shady Hills Generating Station is located in Pasco County, which is classified as an attainment area for all criteria pollutants. Therefore, nonattainment new source requirements are not applicable.

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 1977 CAA Amendments, 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 project will be subject to one or more NSPS. NSPS have been established pursuant to 40 CFR Part 60, Subpart GG for combustion turbines. On February 18, 2005, EPA proposed new NSPS for

Stationary Combustion Turbines that will commence construction after February 18, 2005. NSPS Subpart KKKK, will replace Subpart GG for combustion turbines in simple cycle mode. The applicability of the final rule is similar to that of 40 CFR Part 60, Subpart GG, except that the final rule applies to new, modified, and reconstructed stationary combustion turbines. The stationary combustion turbines subject to subpart KKKK, 40 CFR Part 60, are exempt from the requirements of 40 CFR Part 60, Subpart GG.

On October 15, 2003, EPA promulgated changes to 40 CFR Part 60, Subpart Kb; that would exempt light oil tanks containing No. 2 light oil by virtue of its vapor pressure (FR Vol. 68, No. 199, Pages 59328-59333).

3.4.1.1 Combustion Turbine

The NSPS in Subpart KKKK limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of the fuel fired, which commenced construction, modification, or reconstruction after February 18, 2005. CTs regulated under Subpart KKKK are exempt from the requirements of Subpart GG of this part.

Subpart KKKK requirements that would apply to the Shady Hill Generating Station are applicable to combustion turbines with heat input at peak load (HHV) 850 MMBtu/hr. The NO_x emissions are limited to 0.43 lb/MW-hr for gas-firing and 1.3 lb/MW-hr for fuel oil firing. These emission rates are approximately equivalent to 15 ppm corrected to 15-percent O_2 when firing natural gas and 42 ppm corrected to 15-percent O_2 when firing fuel oil.

For SO_2 emissions, Subpart KKKK requirements limit any gases which contain SO_2 in excess of 110 nano-grams per Joule (ng/J) (0.90 lb/MW-hr) gross output or any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. When turbines simultaneously fire multiple fuels, each fuel must meet this requirement.

In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring. These are summarized below:

40 CFR 60.7 Notification and Record Keeping

1. Notification of the date of construction - 30 days after such date.
2. Notification of actual date of initial start-up - within 15 days after such date.
3. Notification of date which demonstrates CEM – postmarked not less than 30 days prior to date.
4. Maintain records of the occurrence and duration of any start-ups, shutdowns, and malfunctions.
5. Excess emissions reports – semi-annually by the 30th day following the end of each six-month period. (Required even if no excess emissions occur).
6. Maintain file of all measurements for 2 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.

3.4.1.2 Emergency Generator

The emergency generator will be subject to the requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, published July 11, 2006 and effective on September 11, 2006. The format of the final standard is an output-based emission standard for PM, NO_X, CO, and non-methane VOC (NMHC) and tiered based on model year. The Project will comply with the recently promulgated NSPS as follows:

Pollutant	NSPS LIMIT (Grams/KW-hr)	Equivalent NSPS (Grams/hp-hr)
Non-Methane Hydrocabon (NMHC) + Nitrogen Oxides	Pre 2007: NA 2007 – 2010: 6.4	NA 4.77
NMHC	Pre 2007: 1.3 2007 – 2010: NA	0.969 NA
Nitrogen Oxides	Pre 2007: 9.2 2007 – 2010: NA	6.86 NA
Carbon Monoxide	Pre 2007: 11.4 2007 – 2010: 3.5	8.5 2.61
Particulate Matter	Pre 2007: 0.54	0.403

Pollutant	NSPS LIMIT (Grams/KW-hr)	Equivalent NSPS (Grams/hp-hr)
(PM_{10})	2007 – 2010: 0.10	0.075
Particulate Matter $(PM_{2.5})$	NA	NA
Sulfur Dioxide	After Oct 1, 2007: 500 ppm max S content of diesel fuel and either 40 cetane index or max aromatic content of 35% vol. Beginning Oct, 1 2010: 15 ppm max S content of diesel fuel and either 40 cetane index or max aromatic content of 35% vol.	

Shady Hills is proposing to comply with the recently promulgated NSPS as BACT for the emergency generator.

3.4.2 National emission standards for hazardous air pollutants

As discussed in Section 2.3, EPA promulgated MACT standards for combustion turbines. The MACT standard is based on emissions of formaldehyde and limits emissions to 91 parts per billion (ppb) by volume (dry) corrected to 15-percent oxygen which is equivalent to 218 lb/10^{12} Btu when firing natural gas and 235 lb/10^{12} Btu when firing light oil. Shady Hills Generating Station will remain a minor source of HAP emissions and as such will not be subject to MACT standards.

3.4.3 Florida Rules

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

3.4.4 Florida Air Permitting Requirements

The FDEP 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, 62-4.210, 62-210.300(1), and 62-212.400 F.A.C. Specific emission standards are set forth in Chapter 62-296, F.A.C.

3.4.5 Local Air Regulations

Pasco County has no specific ordinances or requirements related to air emissions or impacts from the Project.

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 area to the site is the Chassahowitzka National Wilderness Area which is about 28 km (17 miles) from the site.

3.5.2 PSD Review

3.5.2.1 Pollutant Applicability

The project is considered to be a major modification because the emissions of several regulated pollutants are estimated to exceed PSD significant emission rates. As shown in Table 3-3, potential emissions from the Project will be major for PM (TSP), PM_{10}, NO_x, and CO. Because the 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 Project's impacts are greater than the proposed EPA Class I significant impact levels. The nearest Class I area to the plant site is about 28 km from the site. A PSD Class I increment-consumption analysis is not required because the Project's impacts are less 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 KKKK. The proposed emissions for the Project will be at or below the specified limits (see Section 4.0).

3.5.2.3 Ambient Monitoring

Based on the estimated pollutant emissions from the proposed plant, a pre-construction ambient air quality monitoring analysis is required for PM_{10}, NO_2, and CO. 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 is available by Rule 62-212.400(3)(e) F.A.C. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

As shown in Table 3-4, the project impacts are predicted to be below the applicable *de minimis* monitoring concentration levels for all pollutants. Therefore, pre-construction monitoring is not required to be submitted for this facility.

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 75 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 facility 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 Clean Air Act 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), continuous emission monitoring (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 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 require the units to hold SO_2 emission allowances. Emission limitations established in the Acid Rain Program are presumed to be less stringent than BACT for new units. An allowance is a market-based financial instrument that is equivalent to one ton of SO_2 emissions. Allowances can be sold, purchased, or traded.

For the Project, SO_2 allowances will be obtained from the market.

Continuous emission monitoring (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 (μg/m³) Primary Standard	AAQS (μg/m³) Secondary Standard	AAQS (μg/m³) Florida	PSD Increments (μg/m³) Class I	PSD Increments (μg/m³) Class II	Significant Impact Levels (μg/m³) [e]
Particulate Matter[a] ($PM_{2.5}$)	Annual Arithmetic Mean	15	15	15	NA	NA	NA
	24-Hour Maximum	35	35	35	NA	NA	NA
Particulate Matter (PM_{10})	Annual Arithmetic Mean	50	50	50	4	17	1
	24-Hour Maximum[b]	150	150	150	8	30	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[c]	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide[c]	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone[d]	8-Hour Maximum	147	147	147	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5	NA	NA	NA

Note: Particulate matter ($PM_{2.5}$) = particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers.
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) The 3-year average of the weighted annual mean PM2.5 concentrations from single or multiple community-oriented monitors must not exceed 15.0 μg/m³. The 3-year average of the 98th percentile of 24-hour concentrations at each population-oriented monitor within an area must not exceed 35 μg/m³ (effective December 17, 2006).
(b) Not to be exceeded more than once per year on average over 3 years.
(c) Not to be exceeded more than once per year.
(d) The 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations measured at each monitor within an area over each year must not exceed 0.075 ppm (effective 60 days after publication in the Federal Register).
(e) Maximum concentrations are not to be exceeded.

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] ($\mu g/m^3$)
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

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.

[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.

Sources: 40 CFR 52.21; Rule 62-212.400.

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

Pollutant	Pollutant Emissions (TPY)		PSD Review
	Potential Emissions from Project[a]	Significant Emission Rate	
Sulfur Dioxide	36	40	No
Particulate Matter [PM(TSP)]	39	25	Yes
Particulate Matter (PM_{10})	39	15	Yes
Nitrogen Dioxide	475	40	Yes
Carbon Monoxide	145	100	Yes
Volatile Organic Compounds	17	40	No
Lead	0.03	0.6	No
Sulfuric Acid Mist	5.4	7	No
Total Fluorides	NEG	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Mercury	6.1×10^{-6}	0.1	No

Note: NEG = Negligible.

[a] A. Based on emissions from operating at base load at 59°F for all pollutants except SO_2:

- 100-percent load, natural gas – 2,390 hours
- 100-percent load, oil firing – 1,000 hours

B. SO_2 emissions based on operations at baseload at 59°F:

- 100-percent load, natural gas – 3,390 hours

Source: Golder, 2008.

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

	Concentration ($\mu g/m^3$)	
Pollutant	Predicted Increase in Impacts[a]	*De Minimis* Monitoring Concentration
Particulate Matter (PM_{10})	0.593	10, 24-hour
Nitrogen Dioxide	0.431	14, annual
Carbon Monoxide	15.5	575, 8-hour

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

[b] Based on simple cycle with natural gas firing for 2,390 hours and fuel oil firing for 1,000 hours.

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, CO, and PM/PM_{10} (Section 3.0).

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 consideration of 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)]. The analysis must, by definition, be specific to the project (i.e., case by case).

4.2 New Source Performance Standards

The NSPS in Subpart KKKK limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of the fuel fired, which commenced construction, modification, or reconstruction after February 18, 2005. CTs regulated under Subpart KKKK are exempt from the requirements of Subpart GG of this part.

Subpart KKKK requirements that would apply to the Shady Hill Generating Station are applicable to combustion turbines with heat input at peak load *(HHV) 850 MMBtu/hr.* The NO_x emissions are limited to 0.43 lb/MW-hr for gas-firing and 1.3 lb/MW-hr for fuel oil firing. These emission rates are approximately equivalent to 15 ppm corrected to 15-percent O_2 when firing natural gas and 42 ppm corrected to 15-percent O_2 when firing fuel oil.

The proposed NO_X emission limits during natural gas firing is 9 ppm corrected to 15-percent O_2 and 42 ppm corrected to 15-percent O_2 when firing oil.

4.3 Best Available Control Technology

4.3.1 Overview of Proposed BACT

In recent permitting actions, FDEP has established BACT for heavy-duty simple-cycle industrial gas turbines like the ones proposed for the Project. The CTs proposed for the project are state-of-the-art GE 7FA units. The FDEP has historically established BACT emission rates based on the use of advanced dry low-NO_x combustors for limiting NO_x, good combustion practices for minimizing CO emissions, and clean fuels (natural gas and distillate oil) for control of PM_{10}. The BACT proposed for Shady Hills's CTs is consistent with these recent FDEP permits.

The Project CTs 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 emission limits constitute BACT for the project.

1. CTs - Natural Gas Fired:
   - The CTs will utilize state-of-the-art dry low-NO_x 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 9 ppmvd at baseload; and
   - Emission of PM_{10} will be limited by firing primarily natural gas and 10 percent opacity.
2. CTs - Fuel Oil Fired.
   - The CT will utilize water injection to achieve gas turbine exhaust NOx levels of no greater than 42 ppmvd (corrected to 15 percent O_2);
   - CO emissions will be limited to 20 ppmvd at baseload;
   - Hours of operation will be limited to an average of 1,000 hours per year per CT; and
   - Emission of PM_{10} will be limited by firing light oil and 10 percent opacity.
3. Emergency Generator
   - Emission equivalent to 40 CFR Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.
   - Hours of operation will be limited to 500 hours per year; and

- Emission of PM10 will be limited by firing light oil and 10 percent opacity.

4. Fuel Gas Heater

- Natural gas firing only.

The gas heater proposed for the Project will have potential emissions for each regulated pollutant of less than 5 TPY. As a result, the generator is classified as an insignificant activity under FDEP Rule 62-213.430(6)(b), F.A.C.

4.3.2 Nitrogen Oxides

4.3.2.1 Feasibility

A review of the most recent BACT determinations for similar projects (Appendix Table B-2) demonstrates that emission levels equal to those proposed for the Project, as a result of the proposed DLN combustion technology, have been approved by regulatory agencies as BACT for similar simple cycle CTs. Available information suggests that feasible control technologies available, and in order of highest to lowest control efficiency, for simple cycle CTs are as follows:

1. Selective catalytic reduction ("Hot" SCR);
2. Dry Low NO_X Combustion (DLN); and
3. Wet-injection for oil firing.

$SCONO_x$™ is commercially available but has not been demonstrated on "F" class combustion turbines. Other available technologies such as NOxOut, Thermal DeNOx, NSCR, and XONON™ Combustion System were evaluated and determined to be technically infeasible or not commercially demonstrated for the Project. Appendix B presents a detailed discussion of NO_x control technologies and their feasibility for the Project.

4.3.2.2 Technology Description

The "Top Down" BACT analysis was performed for the following alternatives:

1. Selective catalytic reduction (SCR) and advanced dry low-NO_x combustors at an emission rate of approximately 3.0 ppmvd corrected to 15 percent O_2 when firing natural gas and 16.8 ppmvd when firing oil.

2. Advanced dry low-NO_x combustors at an emission rate of 9 ppmvd corrected to 15 percent O_2 when firing gas.

3. Wet Injection at an emission rate of 42 ppmvd corrected to 15 percent O_2 when firing oil.

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 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 nine ppmvd (corrected to 15 percent O_2) or less while burning only natural gas.

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 9 ppmvd.

While "hot" SCR is technically feasible for the Project, BACT emission levels equivalent to SCR control have not been permitted on similar sized simple cycle CTs by FDEP or any other State agency in EPA Region IV (See Appendix B, Table B-2).

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 combustion turbines. Advanced in this context are the larger (over 150 MW) and more efficient (higher initial firing temperatures and lower heat rate) combustion turbines. This technology is truly pollution prevention because NO_x emissions are inhibited from forming.

Wet injection was the first combustion technology introduced for combustion turbines (pre-1980s) and was the primary method of reducing NO_x emissions from CTs prior to the 1990s. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil. When firing light oil, NOx is limited using water injection to 42 ppmvd corrected to 15 percent O_2.

Although SCONO$_x$™ is potentially available, it has not been demonstrated on "F" Class or larger combustion turbines. The SCONO$_x$™ system has been only operated on a 32-MW facility in California since 1996 and a 5-MW unit in Massachusetts since 1999. The scale up of this complicated technology should not be underestimated. The SCONO$_x$™ technology installed on an "F" Class turbine would involve about a dozen or more different chambers of catalyst for absorption and regeneration. Every 15 to 30 minutes, dampers would be operated to isolate a particular catalyst chamber for regeneration. Each regeneration cycle must isolate the chamber so that O_2 is not introduced and regeneration gas (hydrogen) is introduced. Seal leaks could be significant as applied to the large volume flows associated with a "F" Class turbine. Although the amount of sulfur in natural gas is very low, the SCONO$_x$™ catalyst is poisoned by sulfur compounds, requiring the installation of the SCOSO$_x$™ to further remove sulfur compounds as part of the overall system. The ability of SCOSO$_x$™ to further remove compounds that will poison the catalyst as part of the overall SCONO$_x$™ system has not been demonstrated when firing light oil. Recent contacts with vendors of SCONO$_x$™ technology have indicated that application of SCONO$_x$ has not been applied on large (80 MW or larger) CTs.

The recent permitting trend for advanced simple-cycle combustion turbines is the use of dry low-NO_x combustors and water injection for fuel oil firing (See Appendix B, Table B-2). Indeed, the recent simple cycle Florida project, Oleander Power Project, L.P. Unit No. 5, has been permitted with this technology. The Oleander project is a similar GE 7FA CT rated at 190 MW and is allowed to operate 3390 hours per year including 500 hours per year on 0.05 % sulfur distillate fuel oil.

As discussed in Section 2.1, the proposed CTs will be fired primarily with natural gas. Ultra low sulfur distillate oil will be used as backup fuel, but not to exceed 1,000 hours per year. The following sections present a summary of the economic, environmental, and energy impacts of the available, technically feasible, and demonstrated control technology and emission rate alternatives for the simple cycle units. Appendix B contains the detailed information on the costs, environmental, and energy impacts.

4.3.2.3 Impacts Analysis

Economic--The total capital costs of SCR for the proposed plant are over \$10,000,000 per CT. The total annualized cost of applying SCR with dry low-NO_x combustion is approximately \$1,800,000. Appendix B contains the detailed cost estimates for the capital and annualized costs. The incremental cost effectiveness of adding SCR to the dry low-NO_x combustors and water injection (for oil firing) is estimated at \$11,633 per ton of NO_x removed. Detail calculations are provided in Appendix B Tables B-4 and B-5.

Environmental--The maximum predicted NO_x impacts using the dry low-NO_x 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 0.013 $\mu g/m^3$, which is about 1.3 percent of the significant impact level. While additional controls beyond dry low-NO_x 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 dry low-NO_x combustor technology is truly "pollution prevention". In contrast, use of SCR on the 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 9 ppm based on reported experience; previous permit conditions have specified this level. Indeed, ammonia emissions could be as high as 33 TPY per unit for the project. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM_{10} and $PM_{2.5}$; up to 5.24 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 Appendix B, Table B-6. This table shows the emissions balance for the Project with and without SCR. As shown, the net reduction in emissions with SCR when all pollutants are considered will be 112 TPY. In addition to criteria pollutants, additional secondary emissions of carbon dioxide would be emitted and were included in Appendix B, Table B-6. As noted from this table, the emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x 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 (RCRA) 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: Clean Air Act (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 2,931,503 kWh per year in potential lost generation. The energy required by the SCR equipment would be about 1,118,700 kWh per yr. Taken together, the total lost generation and energy requirements of SCR of 4,050,203 kWh per year could supply the monthly electrical needs of about 338 residential customers. To replace this lost energy, an additional 39 x 10^{10} British thermal units per year (Btu/yr) or about 39 million cubic feet per year (ft^3/yr) of natural gas would be required.

Technology Comparison--The project will use an advanced heavy-duty industrial gas turbine with advanced dry low-NO_x 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 dry low-NO_x 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 dry low-NO_x 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 9,385 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 dry low-NO_x 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 dry low-NO_x 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.

4.3.2.4 Proposed BACT and Rationale

The proposed BACT for the Project is advanced dry low-NO_x 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 dry low-NO_x pollution prevention technology.

2. The estimated incremental cost of SCR is approximately $11,633 per ton of NO_x removed and is similar to 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 155 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 33 TPY per unit.

    b. Additional particulate matter may be formed through the reaction of ammonia and sulfur oxides forming ammonium salts. As much as 5.24 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 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 4.5 TPY of criteria pollutants. Additional emissions of carbon dioxide would also result.

    d. The "net" cost effectiveness, when factoring in the net emission reduction including all criteria pollutants, could be as high as $16,000 per ton of pollutant removed.

4. The energy impacts of SCR will reduce potential electrical power generation by more than 4 million kilowatt hours (kWh) per year. This amount of energy is sufficient to provide the monthly electrical needs of 338 residential customers.

5. To our knowledge, there are no operating simple cycle GE 7FAs with a hot SCR. Furthermore, we understand that there is currently no data available from GE Energy regarding the long term effect on output degradation on the GE 7FA system using a hot SCR.

6. The proposed BACT (i.e., dry low-NO_x combustion) provides the most cost effective control alternative, is pollution preventing, and results in low environmental impacts (less than the significant impact levels). Dry low-NO_x combustion at the proposed emissions levels has been adopted previously in BACT determinations in Florida and in other jurisdictions. Indeed, compared to conventional CTs, the use of the proposed CTs will potentially result in 10 to 15 percent less NO_x emission while producing the same amount of electricity.

4.3.3 Carbon Monoxide

4.3.3.1 Feasibility

A review of the most recent BACT determinations for similar projects (Appendix Table B-3) demonstrates that emission levels equal to those proposed for the Project have been approved by regulatory agencies as BACT for similar simple cycle CTs. Available information suggests that feasible control technologies available, and in order of highest to lowest control efficiency, for simple cycle CTs are as follows:

1. Oxidation catalytic reduction; and
2. Good Combustion Practice.

4.3.3.2 Technology Description

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.

The "Top Down" BACT analysis was performed for the following alternatives:

1. Oxidation catalyst at 80 percent removal; maximum annual CO emissions are 11 TPY per unit; and
2. Combustion controls at 9 ppmvd when firing natural gas (at baseload) and 20 ppmvd when firing oil (at baseload).

4.3.3.3 Impact Analysis

Economic--The estimated capital and annualized cost of a CO oxidation catalyst are approximately $1,440,000 and $522,000 per unit, respectively. The resulting cost effectiveness is 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. Actual CO emissions are likely to be much less than the GE guarantee rate of 9 ppmvd and as a result the cost effectiveness based on actual emissions would be much higher than $9,000 per ton of CO removed. Detail calculations are provided in Appendix B Tables B-7 and B-8

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 ambient air quality standards. 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 1,172,600 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 98 residential customers for a year. To replace this lost energy, about 1.2 x 10^{10} Btu/yr or about 12 million ft^3/yr of natural gas would be required.

4.3.3.4 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 9 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 $1.4 million per unit, with an annualized cost of $522,000 per year per unit); and
3. Recent similar projects in Florida have been authorized with BACT emission limits of 9 ppmvd on gas and 20 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. The cost of an oxidation catalyst would be significant and not be cost effective given the maximum proposed emission limits.

4.3.4 PM/PM_{10}

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 (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the project.

There are no technically feasible methods for controlling the PM/PM_{10} emissions from CTs, other than the inherent quality of the fuel. Clean fuels, natural gas and distillate oil represent BACT for PM/PM_{10} emissions.

4.3.5 Emergency Generator

The emergency generator proposed for the project will utilize clean fuel (i.e., ultra low sulfur light oil) and good combustion techniques to minimize emissions. The emergency generator will be subject to the requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, published July 11, 2006 and effective on September 11, 2006. Shady Hills is proposing to comply with the recently promulgated NSPS as BACT for the emergency generator.

4.3.6 Gas Heater

The proposed BACT for the gas heater is the use of natural gas to limit emissions of PM, and good combustion practices to limit emissions of NO_x, and CO. Natural gas is the cleanest fossil fuel and will minimize the emissions of PM to emission levels recognized as BACT (Table 2-4). Emissions from the gas heater will be minimized to an expected NO_x emission rate of 0.095 lb/MMBtu.

The use of alternate controls such as SCR or SNCR is neither cost effective nor practicable. There are no alternative controls for these small combustion units (i.e., 10 MMBtu/hr of less). The gas heater proposed for the Project will have potential emissions for each regulated pollutant of less than 5 TPY. As a result, the generator is classified as an insignificant activity under FDEP Rule 62-213.430(6)(b), F.A.C.

Table 4-1. Proposed BACT Emission Limitations and Compliance Methods For The Project.

Emission Unit / Pollutant	Emission Rate (Basis)	Conditions	Compliance Method Proposed
CTs (EU 005 and EU 006)			
Nitrogen Oxides (NO_x)	9/42 ppmvd corrected to 15-percent O_2 for gas and oil firing, respectively.	50 to 100 percent load	EPA Method 7E Initial Test; CEM 24-block average
Carbon Monoxide (CO)	9/20 ppmvd for gas and oil firing, respectively.	50 to 100 percent load	EPA Method 10 Initial Test
Particulate Matter (PM)	9/17 lb/hr (dry, filterable)	50 to 100 percent load	VE < 10%
Emergency Generator (EU 007)			
NO_x	3.8 g/hp-hr (40 CFR 60 Subpart IIII)	Normal Operation	500 hours per year operation, low sulfur distillate.
CO	2.6 g/hp-hr (40 CFR 60 Subpart IIII)	Normal Operation	500 hours per year operation, low sulfur distillate.
PM	0.075 g/hp-hr (40 CFR 60 Subpart IIII)	Normal Operation	500 hours per year operation, low sulfur distillate.
Gas Heater (EU 008)			
NO_x	100 lb/MMscf (AP-42)	Normal Operation	Natural Gas Combustion Only.
CO	84 lb/MMscf (AP-42)	Normal Operation	Natural Gas Combustion Only.
PM	1.9 lb/MMscf (AP-42)	Normal Operation	Natural Gas Combustion Only.

Source: Golder, 2008.

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

6.1.1 Site Vicinity

The general modeling approach followed the EPA and FDEP modeling guidelines for determining compliance with AAQS and PSD increments. For all criteria pollutants that will be emitted in excess of the PSD significant emission rate due to a proposed project, a significant impact analysis is performed to determine whether the emission and/or stack configuration changes due to the Project alone will result in predicted impacts that are in excess of the EPA significant impact levels. For the Project, emission increases above the PSD significant emission rate occur for the following criteria pollutants:

- Nitrogen oxides (NO_x);
- Particulate matter (PM);
- PM with aerodynamic diameters less than or equal to 10 microns (PM_{10}); and
- Carbon monoxide (CO)

As AAQS and PSD increments do not exist for total PM, air impacts for that pollutant are not required.

If the project-only impacts are above the significant impact levels in the vicinity of the facility, then two additional and more detailed air modeling analyses are required. The first analysis demonstrates compliance with federal and Florida AAQS, and the second analysis demonstrates compliance with allowable PSD Class II increments. 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. If the receptor spacing in the area in which the maximum predicted concentrations occur is greater than 100 meters (m), additional modeling refinements with a denser receptor grid are performed to reduce the final receptor resolution to 100 m or less.

6.1.2 PSD Class I Areas

Generally, if a major new source is located within 200 km of a PSD Class I area, then a significant impact analysis is also performed to evaluate the impact due to the Project alone at the PSD Class I area. The Chassahowitzka National Wilderness Area (NWA), located about 28 km from the project site, is the only PSD Class I area that is within 200 km from the project site. At the request of the Federal Land Managers (FLM), the maximum predicted impacts at PSD Class I areas within 200 km of the Project are compared to EPA's proposed significant impact levels for PSD Class I areas. These recommended levels are the currently accepted criteria to determine whether a proposed project will incur a significant impact on a PSD Class I area.

If Project-only impacts at the PSD Class I area are above the proposed EPA PSD Class I significant impact levels, then a cumulative analysis is performed to demonstrate compliance with allowable PSD Class I impacts at the PSD Class I area.

For each pollutant emitted in excess of the EPA significant emission rate, additional analyses are required to determine the Project's impact on Air Quality Related Values (AQRV) at a PSD Class I area. For the Chassahowitzka NWA PSD Class I area, the AQRVs of interest are visibility impairment and sulfur and nitrogen deposition.

For a PSD Class I area that is located within 50 km of a proposed project site, visibility impairment is in the form of plume blight. For a PSD Class I area that is located beyond 50 km from a proposed project site, visibility impairment is in the form of regional haze. Visibility impairment is determined for a 24-hour averaging time. For deposition, the total nitrogen and total sulfur depositions are predicted for the annual time period.

6.2 Pre-Construction 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 maximum predicted pollutant impacts are below the *de minimis* concentration levels, the Project is exempt from preconstruction ambient monitoring requirements for each evaluated pollutant.

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 five 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 highest second high (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 ambient air quality standards and allowable PSD increments, which permit a short-term average concentration to be exceeded once per year at each receptor.

For PM_{10} only, compliance with the 24-hour AAQS is determined from the sixth-highest concentration at any receptor over the five year period of record.

To predict the maximum annual and short-term concentrations for the project, the modeling approach is generally divided into screening and refined phases. Concentrations are predicted for the screening phase using a coarse receptor grid and a five-year meteorological data record. If the highest concentration is predicted at a receptor that lies in an area where the receptor spacing is more than 100 m, then a refined analysis is performed in that area using a receptor grid of greater resolution. Modeling refinements are performed using a receptor spacing of 100 m with a receptor grid centered on the screening receptor at which the maximum concentration was predicted. The air dispersion model is then executed with the refined grid for the entire year of meteorology during which the screening concentration occurred. If the maximum Project impacts are predicted in the screening phase in an area in which the receptor spacing is 100 m, then no additional modeling refinements are needed.

6.4 Model Selection

The selection of one or more air quality models to estimate maximum air quality impacts must be based on the models' ability to simulate impacts in all key areas surrounding the project site. For predicting concentrations at receptors that are located within 50 km of a project, FDEP recommends using the American Meteorological Society and EPA Regulatory Model (AERMOD) dispersion model. AERMOD calculates hourly concentrations based on hourly meteorological data and is applicable for most applications since it is recognized as containing the latest scientific algorithms for simulating plume behavior in all types of terrain. Because the Chassahowitzka NWA PSD Class I area is the only PSD Class I area located within 200 km of the project site and is also located entirely within 50 km of the project site, AERMOD was selected to predict all pollutant concentrations for the Project.

AERMOD Version 07026 is the most recent available version on EPA's Internet web site: Support Center for Regulatory Air Models (SCRAM) within the Technology Transfer Network (TTN). A listing of AERMOD features is presented in Table 6-1. For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA and are incorporated as the regulatory default options in AERMOD:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural mode,
5. Default vertical potential temperature gradients, and
6. Calm wind processing.

For this project, the EPA regulatory default options were used to address maximum impacts.

AERMOD was used to provide maximum pollutant concentrations for the annual and 24-, 8-, 3-, and 1-hour averaging times. When evaluating the Project's impacts only for comparison to the Class I and Class II significant impact levels and the *de minimis* monitoring levels, a generic emission rate of 10 grams per second (g/s) was initially used to represent the emissions for the proposed CT sources. Maximum pollutant-specific air impacts for the CTs 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).

6.5 Meteorological Data

Meteorological data used in AERMOD 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) office located at the Tampa International Airport. Concentrations were predicted using five years of hourly meteorological data from 2001 through 2005. The NWS office at Tampa is located approximately 74 km to the west of the project site.

AERMOD incorporates land use parameters for determining boundary layer parameters that are used for dispersion. Current air modelling guidance suggests that the land use parameters should be representative of the data measurement site (i.e., NWS at Tampa). In January 2008, EPA released new recommendations for determining the surface land use characteristics in its AERMOD Implementation Guide. The Guide recommends the following procedures:

- Surface roughness length should be based on an inverse-distance weighted geometric mean for the default upwind distance of 1 kilometer relative to the measurement site.
- Bowen ratio should be based on a simple, unweighted geometric mean over a default 10 km by 10 km domain. There should be no direction or distance dependency for the data.

- The albedo should be based on a simple unweighted arithmetic mean for the same domain used for the Bowen ratio.

AERSURFACE Version 08009 (EPA, January 9, 2008) was used to calculate these surface characteristics. Land cover data was obtained from the U.S. Geological Survey (USGS) National Land Cover Data 1992 archives (NLCD92) in the form of a GeoTIFF file covering the entire state of Florida. The USGS data were downloaded from the following website: http://edcftp.cr.usgs.gov/pub/data/landcover/states/.

AERSURFACE was used to determine the seasonal surface characteristics within a 1 kilometer radius of the Tampa International Airport ASOS met tower, using twelve 30-degree wind direction sectors. Options were set to specify that the measurement site does not see continuous snow cover for most of the winter, is an airport, and is not within an arid region. The last option is to specify the surface moisture. To determine whether the site is wet, dry or average for each evaluated year, 30-years of annual precipitation records were analyzed from the Local Climatological Data (LCD) Annual Summary report for Tampa.

Thirty years of annual precipitation data were ranked to determine which years, 2001 through 2005, fall into the lower 30th percentile indicating drier than normal moisture conditions fall into the upper 30th percentile indicating wet than normal moisture conditions or are reflective of average moisture conditions for this area. The analysis results indicated that years 2001 and 2003 experienced normal moisture conditions 2002 and 2004 experienced wetter than normal moisture conditions and 2005 experienced drier than normal moisture conditions. AERSURFACE was run for each of these surface moisture conditions and the output land use parameters were entered into AERMET version 06341 Stage 3 input to process the surface and profile files for input to AERMOD. The AERSURFACE output and the LCD annual summary data for Tampa are included in Appendix C.

6.6 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 and 2-2. The emission and stack operating parameters presented for 20°F, 59°F, and 95°F ambient temperatures for both natural gas and ultra-low sulfur fuel oil were used in the modeling to determine the maximum air quality impacts for a range of possible CT operating conditions. The proposed CTs will have a stack height of 75 ft and an inner stack diameter of 22 ft.

Nine CT modeling scenarios were evaluated for each fuel type:

1. Base operating load at an inlet temperature of 20°F;
2. Base operating load at an inlet temperature of 59°F;
3. Base operating load at an inlet temperature of 95°F;
4. 75 percent operating load at an inlet temperature of 20°F;
5. 75 percent operating load at an inlet temperature of 59°F;
6. 75 percent operating load at an inlet temperature of 95°F;
7. 50 percent operating load at an inlet temperature of 20°F;
8. 50 percent operating load at an inlet temperature of 59°F; and
9. 50 percent operating load at an inlet temperature of 95°F.

The annual average concentrations from the CT load analysis were predicted for both gas-firing and fuel oil-firing based on two CTs operating all year on each respective fuel since these units could operate anytime during the year with either fuel. However, each unit will be restricted to operate for no more than 3,390 hours per year. As a result, the maximum annual average concentrations are based on the higher impacts of gas-firing for 3,390 hours per year or gas-firing for 2,390 hours per year of gas-firing with oil-firing for 1,000 hours per year.

Based on the critical CT load and ambient temperature, determined from the CT load analysis for a particular pollutant and receptor area, the following pollutant-specific significant impact analyses were performed that included the impacts of the gas-fired heater:

<u>At the Site Vicinity</u>

- PM_{10} - Oil-firing, 50% Load, 95 °F
- NO_2 - Oil-firing, Base Load, 20 °F
- CO - Oil-firing, Base Load, 20 °F

<u>At Chassahowitzka NWA PSD Class I Area</u>

- PM_{10} - Oil-firing, 50% Load, 95 °F
- NO_2 - Oil-firing, Base Load, 20 °F

For the pollutant-specific analyses, the annual PM_{10} and NO_2 impacts are based on operating 2,390 hours per year on natural gas and 1,000 hours per year on fuel oil.
Per EPA air modeling guidelines, an NO_2/NO_X ratio of 75 percent is also assumed for the pollutant-specific NO_2 results. The results were compared to the PSD Class I and Class II significant impact levels.

The locations of the CTs and fuel heater are shown in Appendix D.

6.7 Receptor Locations

6.7.1 Site Vicinity

The modeling analysis used Universal Transverse Mercator (UTM) coordinates from zone 17, North American Datum 1927 (NAD27). Nested Cartesian receptor grids were used in addition to discrete Cartesian receptors along the Shady Hills property boundary. The significant impact analysis used the following receptor spacing:

- 50-m intervals along the property boundary;
- 100-m intervals beyond the property boundary to two km; and
- 250-m intervals from two to five km.

These receptor locations are shown in Appendix D. Modeling refinements were performed, as needed, to ensure that the maximum predicted impacts occur in an area with a receptor resolution no greater than 100 m.

6.7.2 Chassahowitzka NWA

A set of 113 Cartesian discrete receptors were obtained from the National Park Service. The receptors were converted into UTM coordinates, NAD27.

Receptor elevations and hill scale heights for all receptors were obtained from 7.5 minute USGS Digital Elevation Model (DEM) data using the AERMOD terrain preprocessor program AERMAP, Version 06341. The extent of the AERMAP domain was sufficient to include all significant impact analysis receptors.

6.8 Building downwash effects

Aerodynamic forces in the vicinity of structures and obstacles, such as buildings, disturb atmospheric flow fields. This flow disturbance near buildings and other structures can enhance the dispersion of emissions from stacks affected by the disturbed flow. The disturbance can also reduce the effective height of emissions from stacks located near buildings and obstacles. The height of these disturbances can be compared to the release points of modeled sources. For sources with release points above these disturbances, the effect on dispersion is not significant. This release height threshold is known as the Good Engineering Practice (GEP) height. GEP stack height is defined in Section 123 of the Clear Air Act Amendments of 1977 as:

> *"the height necessary to ensure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, and wakes which may be created by the source itself, nearby structures, or nearby terrain obstacles."*

The EPA Guideline for Determination of Good Engineering Practice Stack Height contains detailed guidance on issues relating to the determination of GEP height. This guidance specifies use of the following formula for "new" stacks (*e.g.*, stacks not in existence until after January 1979) for calculating the minimum stack height for which the adverse aerodynamic effects are avoided:

$$H_{GEP} = H_B + 1.5\,L$$

Where: H_{GEP} = GEP formula stack height
H_B = height of building or nearby structure
L = lesser of the height or projected width of the structure

The formula for stacks in existence before 1979 is:

$$H_{GEP} = 2.5\,H_B$$

Both the height and projected width of the structure are determined from the projection of the structure on a plane perpendicular to the direction of the wind. The downwind area in which a nearby structure is presumed to have a significant effect on a stack is defined as 5L. Therefore, the GEP formula heights calculated by the formulas listed above are only applicable to stacks that are located within 5L of the building or structure in question. All proposed stack heights are less than the calculated GEP formula heights.

The only significant structures in the vicinity of the proposed CT stacks are the proposed CT air filter inlets and CT structure. 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

Building dimensions for the project's structures were entered into the EPA's Building Profile Input Program (BPIPPRM, Version 04274) for the purpose of developing wind direction-specific building dimensions for input to AERMOD. The BPIP summary files are presented in Appendix D.

6.9 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 6-3. The maximum pollutant concentrations predicted in the screening analysis for a single CT and 2 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 proposed CTs only and the proposed CTs and gas heater are compared to the Class II significant impact levels in Table 6-4. The maximum predicted PM_{10}, NO_2, and CO impacts due to the Project are all below the significant impact levels. Because the Project 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_{10}, NO_2 and CO impacts due to the Project are also below the *de minimis* monitoring levels. Because the Project will not have predicted impacts greater than *de minimis* levels, preconstruction monitoring data are not required to be submitted as part of this application.

The modeling analysis results for the Project at the Chassahowitzka NWA are summarized in Tables 6-5 through 6-6. The maximum pollutant concentrations predicted in the screening analysis for a single CT and 2 CTs firing natural gas and distillate fuel oil are presented in Tables 6-5 and 6-6, respectively. A summary of maximum pollutant concentrations predicted for the project is compared to the Class I significant impact levels in Table 6-7.

As shown in Table 6-7, the maximum predicted PM_{10} and NO_2 impacts due to the Project are below EPA's proposed PSD Class I significant impact levels. Therefore, more detailed modeling analyses for determining compliance with the allowable PSD Class I increments are not required for these pollutants.

Summaries of the AERMOD model results and sample model input file are provided in Appendix E.

TABLE 6-1

MAJOR FEATURES OF THE AERMOD MODEL, VERSION 07026

AERMOD Model Features
• Plume dispersion/growth rates are determined by the profile of vertical and horizontal turbulence, vary with height, and use a continuous growth function.
• In a convective atmosphere, uses three separate algorithms to describe plume behavior as it comes in contact with the mixed layer lid; in a stable atmosphere uses a mechanically mixed layer near the surface.
• Polar or Cartesian coordinate systems for receptor locations can be included directly or by an external file reference.
• Urban model dispersion is input as a function of city size and population density; sources can also be modeled individually as urban sources.
• Stable plume rise: uses Briggs equations with winds and temperature gradients at stack top up to half-way up to plume rise. Convective plume rise: plume superimposed on random convective velocities.
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash.
• Has capability of simulating point, volume, area, and multi-sized area sources.
• Accounts for the effects of vertical variations in wind and turbulence (Brower *et al.*, 1998).
• Uses measured and computed boundary layer parameters and similarity relationships to develop vertical profiles of wind, temperature, and turbulence (Brower *et al.*, 1998).
• Concentration estimates for 1-hour to annual average times.
• Creates vertical profiles of wind, temperature, and turbulence using all available measurement levels.
• Terrain features are depicted by use of a controlling hill elevation and a receptor point elevation.
• Modeling domain surface characteristics are determined by selected direction and month/season values of surface roughness length, Albedo, and Bowen ratio.
• Contains both a mechanical and convective mixed layer height, the latter based on the hourly accumulation of sensible heat flux.
• The method of Pasquill (1976) to account for buoyancy-induced dispersion.
• A default regulatory option to set various model options and parameters to EPA-recommended values.
• Contains procedures for calm-wind and missing data for the processing of short term averages.

Note: AERMOD = American Meteorological Society and Environmental Protection Agency Regulatory Model.
Source: Paine *et al.* 2007.

TABLE 6-2
MAXIMUM CONCENTRATIONS PREDICTED FOR ONE CT FIRING NATURAL GAS AND ULTRA LOW SULFUR FUEL OIL
IN SIMPLE-CYCLE OPERATION IN THE PROJECT VICINITY

Pollutant	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature: Base Load 20°F	Base Load 59°F	Base Load 95°F	75% Load 20°F	75% Load 59°F	75% Load 95°F	50% Load 20°F	50% Load 59°F	50% Load 95°F	Averaging Time	Maximum Predicted Concentrations (ug/m3) by Operating Load and Air Temperature [a]: Base Load 20°F	Base Load 59°F	Base Load 95°F	75% Load 20°F	75% Load 59°F	75% Load 95°F	50% Load 20°F	50% Load 59°F	50% Load 95°F
Natural Gas																			
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0890	0.0925	0.0977	0.1078	0.1125	0.1162	0.1296	0.1330	0.1385
(10 g/s)										24-Hour	0.7207	0.7620	0.8220	0.9371	0.9939	1.0480	1.2502	1.3090	1.4089
										8-Hour	1.7916	1.8688	1.9819	2.1896	2.2812	2.3534	2.6275	2.7232	2.9197
										3-Hour	2.3804	2.5034	2.6898	3.0516	3.2845	3.4691	4.1312	4.3010	4.7084
										1-Hour	4.2244	4.3971	4.7322	5.3628	5.6763	6.0062	7.3695	7.7487	8.3544
PM_{10}	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	Annual	0.0101	0.0105	0.0111	0.0122	0.0128	0.0132	0.0147	0.0151	0.0157
										24-Hour	0.0817	0.0864	0.0932	0.1063	0.1127	0.1188	0.1418	0.1484	0.1598
NO_x	63.6	59.4	53.8	51.7	47.8	44.1	40.3	37.8	34.8	Annual	0.071	0.069	0.066	0.070	0.068	0.065	0.066	0.063	0.061
CO	32.1	29.7	26.8	24.1	23.9	22.2	20.4	19.9	18.8	8-Hour	0.73	0.70	0.67	0.66	0.69	0.66	0.68	0.68	0.69
										1-Hour	*1.71*	*1.65*	*1.60*	*1.63*	*1.71*	*1.68*	*1.90*	*1.94*	*1.98*
Ultra Low-Sulfur Fuel Oil																			
Generic[b]	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0874	0.0909	0.0960	0.1063	0.1095	0.1139	0.1298	0.1314	0.1369
(10 g/s)										24-Hour	0.7040	0.7429	0.8020	0.9200	0.9570	1.0134	1.2534	1.2823	1.3793
										8-Hour	1.7558	1.8331	1.9446	2.1599	2.2234	2.3094	2.6314	2.6803	2.8526
										3-Hour	2.3272	2.4467	2.6279	2.9873	3.1323	3.3564	4.1402	4.2222	4.5837
										1-Hour	4.1436	4.3188	4.6186	5.2728	5.4677	5.8183	7.3885	7.5814	8.1797
PM_{10}	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.0187	0.0195	0.0206	0.0228	0.0234	0.0244	0.0278	0.0282	0.0293
										24-Hour	0.151	0.159	0.172	0.197	0.205	0.217	0.268	0.275	0.295
NO_x	345.9	322.3	293.5	280.4	263.3	239.2	214.9	203.6	185.2	Annual	0.381	0.369	0.355	0.375	0.363	0.343	0.351	0.337	0.319
CO	71.1	66.2	60.5	52.2	50.6	48.3	44.2	43.4	41.3	8-Hour	1.57	1.53	1.48	1.42	1.42	1.41	1.46	1.47	1.48
										1-Hour	3.71	3.60	3.52	3.47	3.48	3.54	4.11	4.15	4.26

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001to 2005 consisting of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

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

TABLE 6-3
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR TWO SIMPLE-CYCLE CTS
FIRING NATURAL GAS AND ULTRA-LOW SULFUR FUEL OIL

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m3) by Operating Load and Air Temperature [a]: Base Load 20°F	Base Load 59°F	Base Load 95°F	75% Load 20°F	75% Load 59°F	75% Load 95°F	50% Load 20°F	50% Load 59°F	50% Load 95°F	EPA Class II Significant Impact Levels (ug/m^3)
Natural Gas											
PM_{10}	Annual	0.0202	0.0210	0.0222	0.0244	0.0255	0.0264	0.0294	0.0302	0.0314	1
	24-Hour	*0.163*	*0.173*	*0.186*	0.213	0.225	0.238	0.284	0.297	0.320	5
NO_x	Annual	0.143	0.138	0.133	0.140	0.135	0.129	0.132	0.127	0.121	1
CO	8-Hour	1.45	1.40	1.34	1.33	1.38	1.32	1.35	1.36	1.38	500
	1-Hour	3.4	3.3	3.2	3.3	3.4	3.4	3.8	3.9	4.0	2,000
Ultra-Low Sulfur Fuel Oil											
PM_{10}	Annual	0.0374	0.0389	0.0411	0.0455	0.0469	0.0488	0.0556	0.0563	0.0586	1
	24-Hour	0.302	0.318	0.344	0.394	0.410	0.434	0.537	0.549	0.591	5
NO_x	Annual	0.76	0.74	0.71	0.75	0.73	0.69	0.70	0.67	0.64	1
CO	8-Hour	3.14	3.06	2.97	2.84	2.83	2.81	2.93	2.93	2.97	500
	1-Hour	7.4	7.2	7.0	6.9	7.0	7.1	8.2	8.3	8.5	2,000

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting 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 CONCENTRATIONS PREDICTED FOR PROPOSED PROJECT
COMPARED TO EPA CLASS II SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Concentration (ug/m^3) [a]			EPA Class II Significant Impact Levels (ug/m^3)
		Natural Gas	Fuel Oil	Maximum [b]	
2 CTs					
PM_{10}	Annual	0.0264	0.049	0.013	1
	24-Hour	0.238	0.434	0.434	5
NO_x	Annual	0.143	0.762	0.094	1
CO	8-Hour	1.5	3.1	3.1	500
	1-Hour	3.4	7.4	7.4	2,000
2 CTs and Fuel Heater					
PM_{10}	Annual	-	0.061	0.013	1
	24-Hour	-	0.593	0.593	5
NO_x [c]	Annual	-	-	0.431	1
CO	8-Hour	-	15.5	15.5	500
	1-Hour	-	21.7	21.7	2,000

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

[b] Maximum annual concentrations are based on CTs firing gas for 2390 hours and oil for 1000 hours per year, base load, 20°F for NO_2 and CO and 50% load, 95°F for PM_{10}.

[c] NO_x to NO_2 conversion factor of 0.75 applied to modeled NO_x impacts based on EPA Modeling Guidelines

TABLE 6-5
MAXIMUM CONCENTRATIONS PREDICTED FOR ONE CT FIRING NATURAL GAS AND ULTRA LOW SULFUR FUEL OIL
IN SIMPLE-CYCLE OPERATION AT THE CHASSAHOWITZKA NWA CLASS I AREA

	Maximum Emission Rates (lb/hr) by Operating Load and Air Temperature										Maximum Predicted Concentrations (ug/m3) by Operating Load and Air Temperature [a]								
	Base Load			75% Load			50% Load			Averaging	Base Load			75% Load			50% Load		
Pollutant	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F	Time	20°F	59°F	95°F	20°F	59°F	95°F	20°F	59°F	95°F
Natural Gas																			
Generic[b] (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0058	0.0059	0.0060	0.0062	0.0063	0.0063	0.0065	0.0066	0.0067
										24-Hour	0.0545	0.0555	0.0569	0.0596	0.0608	0.0617	0.0649	0.0657	0.0670
										8-Hour	0.1295	0.1307	0.1324	0.1355	0.1370	0.1380	0.1436	0.1455	0.1467
										3-Hour	0.2905	0.2932	0.2971	0.3045	0.3079	0.3104	0.3188	0.3209	0.3242
										1-Hour	0.6700	0.6799	0.6945	0.7219	0.7347	0.7441	0.7779	0.7867	0.8009
PM_{10}	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	Annual	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0008
										24-Hour	0.0062	0.0063	0.0065	0.0068	0.0069	0.0070	0.0074	0.0075	0.0076
NO_x	63.6	59.4	53.8	51.7	47.8	44.1	40.3	37.8	34.8	Annual	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.003
CO	32.1	29.7	26.8	24.1	23.9	22.2	20.4	19.9	18.8	8-Hour	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04
										1-Hour	0.27	0.25	0.23	0.22	0.22	0.21	0.20	0.20	0.19
Ultra Low-Sulfur Fuel Oil																			
Generic[b] (10 g/s)	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	79.37	Annual	0.0058	0.0059	0.0060	0.0062	0.0062	0.0063	0.0066	0.0066	0.0067
										24-Hour	0.0542	0.0550	0.0564	0.0592	0.0600	0.0611	0.0650	0.0654	0.0666
										8-Hour	0.1290	0.1301	0.1318	0.1350	0.1360	0.1373	0.1437	0.1447	0.1478
										3-Hour	0.2892	0.2919	0.2958	0.3034	0.3057	0.3088	0.3190	0.3200	0.3232
										1-Hour	0.6655	0.6754	0.6897	0.7179	0.7264	0.7381	0.7784	0.7828	0.7968
PM_{10}	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	17.0	Annual	0.0012	0.0013	0.0013	0.0013	0.0013	0.0013	0.0014	0.0014	0.0014
										24-Hour	0.012	0.012	0.012	0.013	0.013	0.013	0.014	0.014	0.014
NO_x	345.9	322.3	293.5	280.4	263.3	239.2	214.9	203.6	185.2	Annual	0.025	0.024	0.022	0.022	0.021	0.019	0.018	0.017	0.016
CO	71.1	66.2	60.5	52.2	50.6	48.3	44.2	43.4	41.3	8-Hour	0.12	0.11	0.10	0.09	0.09	0.08	0.08	0.08	0.08
										1-Hour	0.60	0.56	0.53	0.47	0.46	0.45	0.43	0.43	0.41

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001to 2005 consisting of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

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

TABLE 6-6
SUMMARY OF MAXIMUM CONCENTRATIONS PREDICTED FOR TWO SIMPLE-CYCLE CTS
AT THE CHASSAHOWITZKA NWA PSD CLASS I AREA

Pollutant	Averaging Time	Maximum Predicted Concentrations (ug/m3) by Operating Load and Air Temperature[a] Base Load 20°F	Base Load 59°F	Base Load 95°F	75% Load 20°F	75% Load 59°F	75% Load 95°F	50% Load 20°F	50% Load 59°F	50% Load 95°F	EPA Class I Significant Impact Levels (ug/m^3)
Natural Gas											
PM_{10}	Annual	0.0013	0.0013	0.0014	0.0014	0.0014	0.0014	0.0015	0.0015	0.0015	0.2
	24-Hour	0.012	0.013	0.013	0.014	0.014	0.014	0.015	0.015	0.015	0.3
NO_x	Annual	0.009	0.009	0.008	0.008	0.008	0.007	0.007	0.006	0.006	0.1
Ultra-Low Sulfur Fuel Oil											
PM_{10}	Annual	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.2
	24-Hour	0.023	0.024	0.024	0.025	0.026	0.026	0.028	0.028	0.029	0.3
NO_x	Annual	0.051	0.048	0.044	0.043	0.041	0.038	0.035	0.034	0.031	0.1

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting 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 CONCENTRATIONS PREDICTED FOR PROPOSED PROJECT COMPARED TO EPA CLASS I SIGNIFICANT IMPACT LEVELS

Pollutant	Averaging Time	Maximum Concentration (ug/m^3) [a]			EPA Class I Significant Impact Levels (ug/m^3)
		Natural Gas	Fuel Oil	Maximum [b]	
2 CTs					
PM_{10}	Annual	0.0015	0.0029	0.001	0.2
	24-Hour	0.0152	0.0285	0.029	0.3
NO_x	Annual	0.0094	0.0507	0.006	0.1
2 CTs and Fuel Heater					
PM_{10}	Annual	-	0.0029	0.003	0.2
	24-Hour	-	0.029	0.029	0.3
NO_x [c]	Annual	-	-	0.007	0.1

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

[b] Annual concentrations based on CTs firing gas for 2390 hours and oil for 1000 hours per year, base load, 20°F for NO_2 and 50% load, 95°F for PM_{10}.

[c] NO_x to NO_2 conversion factor of 0.75 applied to modeled NO_x impacts based on EPA Modeling Guidelines

7.0 ADDITIONAL IMPACT ANALYSIS

This section presents the impacts the Project will have on vegetation, soils, visibility, and direct growth resulting from the Project, both in the surrounding area and the nearest PSD Class I area of Chassahowitzka National Wilderness Area (NWA).

7.1 Impacts Due to Associated Direct Growth

7.1.1 Introduction

Rule 62-212.400(3)(h)(5), F.A.C., states that an application must include information relating to the air quality impacts of, and the nature and extent of all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the proposed construction and operation of the Shady Hills facility. This information is consistent with the EPA Guidance related to this requirement in the *Draft New Source Review Workshop Manual* (EPA, 1990).

In general, there has been moderate growth in the general area since 1977. The site is located in about the geographic northwest of Pasco County which is on Florida's West coast, near the Gulf of Mexico. Pasco County is bounded by Hernando County to the north, Hillsborough County to the south/southeast, Pinellas County to the south/southwest, Polk County and Sumter County to the east. Pasco County is the 50th fastest growing county in the country with a 30.6 percent increase and has grown by 105,403 residents since the year 2000. Pasco County comprises a 745 -square mile area.

The Shady Hills Generation Station's Emission Units 005 and 006 are being constructed to meet current and projected electric demands. Shady Hills has an obligation to meet this increase in electric demand. Additional growth as a direct result of the additional electric power provided by the Shady Hills Generating Station is not expected.

After completion of the Project, the facility will employ a total of 11 operational workers, two more than current plant staffing. The workforce needed to operate the project represents a small fraction of the population already present in the immediate area. Therefore, while there would be a small increase in vehicular traffic in the area, the effect on air quality levels would be minimal.

There are also expected to be no air quality impacts due to associated commercial and industrial growth given the location of the project. The existing commercial and industrial infrastructure should be adequate to provide any support services that the project might require and would not increase with the operation of the facility. The addition of the two nominal 180-MW units will have little effect on the increase or growth in the area.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Pasco County. As such, the information presents information available from a variety of sources (i.e., Florida Statistical Abstract, FDEP, etc.) that characterize Pasco County as a whole.

7.1.2 Residential Growth

7.1.2.1 Population and Household Trends

As an indicator of residential growth, the trend in the population and number of household units in Pasco County since 1977 are shown in Figure 7-1. The county experienced a 198-percent increase in population for the years 1977 through 2006. During this period, there was an increase in population of about 282,091. Similarly, the number of households in the county increased by about 117,219, or 181 percent, since 1977.

7.1.2.2 Growth Associated with the Operation of the Project

Since there will only be two additional operational workers needed for the Project, residential growth due to the Shady Hills Project will be minimal.

7.1.3 Commercial Growth

7.1.3.1 Retail Trade and Wholesale Trade

As an indicator of commercial growth in Pasco County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 7-2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices that sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977, retail trade has increased by 642 establishments and 11,537 employees or 116 and 202-percent, respectively. For the same period, wholesale trade has increased by 349 establishments and 1,760 employees, or 459 and 461 percent, respectively.

7.1.3.2 Labor Force

The trend in the labor force in Pasco County since 1977 is shown in Figure 7-3. The greatest number of persons employed in Pasco County has been in the agricultural and manufacturing services. Between 1977 and 2006, approximately 144,056 persons were added to the available work force, for an increase of 332 percent.

7.1.3.3 Tourism

Another indicator of commercial growth in Pasco County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 7-4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1977 and 2007, there was a decrease in the number of hotels and motels in the county; however, there was a significant increase of 52 percent in the number of units at those facilities.

7.1.3.4 Transportation

The county's main arteries are Interstate 75 and U.S. Highway 31, which run north-south through the eastern section of the county and State Road 589 (Suncoast Parkway), U.S. Highway, U.S. Route 41, and U.S. Route 19, which run north-south through the western section of the county. In addition, State Road 52 and State Road 54 traverse the county from east to west.

7.1.3.5 Growth Associated with the Operation of the Project

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the Project. The workforce needed to operate the Project represents a small fraction of the labor force present in the immediate and surrounding areas.

7.1.4 <u>Industrial Growth</u>

7.1.4.1 Manufacturing and Agricultural Industries

As an indicator of industrial growth, the trend in the number of employees in the manufacturing industry in Pasco County since 1977 is shown in Figure 7-5. As shown, the manufacturing industry experienced a significant increase of 25 percent from 1977 through 2006.

The trend in the number of employees in the agricultural industry, in Pasco County since 1977 is also shown in Figure 7-5. As shown, the agricultural industry experienced a decrease in employment of 64 percent from 1977 through 2006.

7.1.4.2 Utilities

Existing power plants in Pasco County include the following:

- Anclote, Progress Energy Florida (PEF), and
- Shady Hills Generating Station.

Together, these power plants have an electrical generating capacity of less than 1,500 megawatts (MW).

As an indicator of electrical utility growth, the electrical generation capacity in Pasco County since 1977 is shown in Figure 7-6.

7.1.4.3 Growth Associated with the Operation of the Project

Since the PSD baseline date of August 7, 1977, there have been only a few major facilities built within a 35-km radius of the plant site. The nearest major source is the Progress Energy Anclote Power Plant. There are a limited number of facilities located throughout the 50-km radius area surrounding the project site. There has not been a concentration of industrial and commercial growth in the vicinity of the project site.

7.1.5 Air Quality Discussion

7.1.5.1 Air Emissions and Spatial Distribution of Major Facilities

Based on actual emissions reported for 1999 (latest year of available data) by EPA on its AIRSdata website, total emissions from stationary sources in the county are as follows:

- SO_2: 34,634 TPY
- PM_{10}: 571 TPY
- $PM_{2.5}$: 515 TPY
- NO_x: 10,182 TPY
- CO: 927 TPY
- VOC: 210 TPY

7.1.5.2 Air Monitoring Data

Since 1977, Pasco County has been classified as attainment or maintenance for all criteria pollutants. Air quality monitoring data have been collected in Pasco County only for ozone (O_3). For this evaluation, the air quality monitoring data collected at the monitoring stations nearest to the Project were used to assess air quality trends since 1977. Air quality monitoring data for all the criteria pollutants were based primarily on monitoring stations located in the neighboring counties (Hillsborough County, Polk County, and Pinellas County). The following stations were considered:

- SO_2 concentrations – Mulberry (Polk), and Ruskin (Hillsborough);
- PM_{10} concentrations – Mulberry, Lakeland, and Nichols (Polk), and Ruskin (Hillsborough);
- NO_2 concentrations – Lakeland (Polk), and Tampa (Hillsborough);

- CO concentrations – Tampa, and Plant City (Hillsborough), and St. Petersburg (Pinellas); and
- O_3 concentrations – Tampa (Hillsborough), St. Petersburg, and Tarpon Springs (Pinellas), and Holiday (Pasco).

Data collected from these stations are considered to be generally representative of air quality in Pasco County. Because these monitoring stations are generally located in more industrialized areas than the Project area, the reported concentrations are likely to be somewhat higher than that experienced at the site.

These data indicate that the maximum air quality concentrations currently measured in the region comply with and are well below the applicable AAQS. These monitoring stations are located in areas where the highest concentrations of a measured pollutant are expected due to the combined effect of emissions from stationary and mobile sources, as well as the effects of meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than the monitored concentrations from these sites.

In addition, since 1988, PM in the form of PM_{10} has been collected at the air monitoring stations due to the promulgation of the PM_{10} AAQS. Prior to 1989, the AAQS for PM was in the form of total suspended particulates (TSP) concentrations, and this form was measured at the stations.

7.1.5.3 SO_2 Concentrations

The trends in the annual, 24-hour, and 3-hour average SO_2 concentrations measured near the Project site since 1977 are presented in Figures 7-7 through 7-9, respectively. SO_2 concentrations have been measured at five stations for various time periods throughout these years. As shown in these figures, annual SO_2 concentrations have been generally below the AAQS and continue to be well below the AAQS for the 24-hour and 3-hr averages.

7.1.5.4 PM_{10}/TSP Concentrations

The trends in the annual and 24-hour average PM_{10} and TSP concentrations since 1977 are presented in Figures 7-10 and 7-11, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to PM_{10}.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS. Since 1988 when PM_{10} concentrations have been measured, the PM_{10} concentrations have been and continue to be below the AAQS.

7.1.5.5 NO_2 Concentrations

The trends in the annual average NO_2 concentrations measured at the nearest monitors to the Shady Hills site are presented in Figure 7-12. As shown in this figure, measured NO_2 concentrations have been generally well below the AAQS.

7.1.5.6 CO Concentrations

The trends in the one-hour and eight-hour average CO concentrations since 1977 are presented in Figures 7-13 and 7-14, respectively. As shown in these figures, measured CO concentrations have been well below the AAQS.

7.1.5.7 Ozone Concentrations

The trends in the 1-hour average ozone concentrations since 1977 are presented in Figure 7-15. The eight-hour average ozone concentrations are presented in Figure 7-16. As shown in these figures, the measured ozone concentrations have been generally below the AAQS.

7.1.5.8 Air Quality Associated with the Operation of the Project

The air quality data measured in the region of the Project indicate that the maximum air quality concentrations are well below and comply with the AAQS. Also, based on the trends presented of these maximum concentrations, the air quality has generally improved in the region since the baseline date of August 7, 1977. Because the maximum concentrations for the Project are predicted to be low and, for certain pollutants, below the significant impact levels, the air quality concentrations in the region are expected to remain below and comply with the AAQS.

7.2 Impacts on Soils, Vegetation, Wildlife and Visibility in the Project's Vicinity

The additional impact analysis addresses the potential impacts of the Project on the 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 project. Because the facility is subject to the PSD NSR requirements for $PM_{10.}$ NO_2, and CO, the additional impact analysis were performed for these pollutants. The analyses also addressed impacts associated with the Project firing natural gas and backup ultra-low sulfur 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 maximum air quality impacts predicted for the project at the Chassahowitzka NWA are also below the EPA's Class I significant impact levels.

7.3 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 site and at 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.

7.4 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 PM_{10}, NO_2, and CO in the vicinity of the Project site are well below the EPA Class II significant impact levels (Table 6-4); therefore, no significant impacts associated with facility operations are expected. The predicted concentrations are less than one 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.

7.5 Class I Area Impact Analysis

7.5.1 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 Project. 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; and
- 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.

7.5.2 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.

7.5.3 Vegetation

7.5.3.1 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.

7.5.3.2 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 $\mu g/m^3$ 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 $\mu g/m^3$ did not appear to be injurious to the tested plants.

By comparison of these published toxicity values for particulate matter exposure (i.e., concentration for an 8-hour averaging time), the possibility of plant damage in the Chassahowitzka NWA can be determined. The maximum predicted 8-hour PM_{10} concentration in the NWA due to the project only is 0.06 $\mu g/m^3$ when firing fuel oil (see Table 7-1). Since this concentration is much less than the minimum concentration that can potentially affect vegetation, no effects to vegetative AQRVs are expected from the project.

7.5.3.3 NO_2

NO2 can injure plant tissue with symptoms usually appearing as irregular white to brown collapsed lesions between the leaf veins and near the margins. Conversely, non-injurious levels of NO2 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 five percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 µg/m3 (Heck and Tingey, 1979). Chronic exposure of selected plants (some considered NO_2-sensitive) to NO_2 concentrations of 2,000 to 4,000 µg/m3 for 213 to 1,900 hours caused reductions in yield of up to 37 percent and some chlorosis (Zahn, 1975). Short term exposure to NO_2 at concentrations of 564 µg/m3 caused adverse effects in lichen species (Holopainen and Karenlampi 1984), while for vascular plants that have been determined to be more sensitive to NO_2 exposure than others, acute (1, 4, 8 hours) exposure caused five percent predicted foliar injury at concentrations ranging from 3,800 to 15,000 µg/m3 (Heck and Tingey, 1979).

The maximum one, three, and eight hour average NO_2 concentrations due to the project are predicted to be 5.93, 2.53, and 1.14 µg/m3, respectively, at the Chassahowitzka NWA PSD Class I area. These maximum concentrations are well below the levels that could potentially injure five percent of vascular plant foliage (i.e., 3,800 to 15,000 µg/m3), and less than 0.1 percent of the concentration that caused acute adverse effects in sensitive lichen species. For a chronic exposure, the maximum annual NO2 concentration due to the project is predicted to be 0.007 µg/m3 at the Chassahowitzka NWA, which is over six orders of magnitude lower than the level that caused minimal yield loss and chlorosis in plant tissue (i.e., 2,000 µg/m3).

Although it has been shown that simultaneous exposure to 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 Chassahowitzka NWA are still far below the levels that potentially cause plant injury for either acute or chronic exposure.

7.5.3.4 CO

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 x 10^6 μg/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 x 10^5 μg/m^3). These plants were considered the species most sensitive to CO-induced inhibition of cytochrome *c* oxidase.

The maximum one-hour average concentration due to the project at the Class I area is 1.30 μg/m, which is about 1 x 10^6 times lower than the minimum value that caused inhibition in laboratory studies (i.e., 6.85 x 10^6 μg/m^3). The amount of damage sustained at this level, if any, for 1 hour would have negligible effects over an entire growing season. The maximum annual concentration predicted at the Class I area is 0.011 μg/m^3 and reflects a more realistic, yet conservative, CO level for the Class I areas. This maximum concentration is predicted to be about 1 x 10^8 times lower than the value that caused cytochrome *c* oxidase inhibition (6.85 x 10^5 μg/m^3).

7.5.3.5 No_x Emissions And Impacts To Ozone

NO_x and VOC emissions are precursors to the formation of O_3. Ozone, although not directly emitted as a result of the project, is formed when NO_x and VOC react in the atmosphere in the presence of sunlight. Natural (i.e., without man-made sources) ambient concentrations of O_3 are normally in the range of 20 to 39 μg/m^3 (0.01 to 0.02 ppm) (Heath, 1975). O_3 can cause various damage to broad-leaved plants including: tissue collapse, interveinal necrosis and markings on the upper surface leaves know as stippling (pigmented yellow, light tan, red brown, dark brown, red, or purple), flecking (silver or bleached straw white), mottling, chlorosis or bronzing, and bleaching. O_3 can also stunt plant growth and bud formation. On certain plants such as citrus, grape, and tobacco, it is common for leaves to wither and drop early.

Ozone sensitive vegetation is present within the Chassahowitzka NWA, including elderberry (*Sambucus canadensis*), smooth cordgrass (*Spartina alterniflora*), and Virginia creeper (*Parthenocissus quinquefolia*) (NPS, 2003).

Elderberry is considered a bioindicator for describing ozone impact thresholds. However, the low levels of ozone exposure at the Class I Area make the risk of foliar ozone injury to plants low (NPS, 2004). Exposure indices, including the Sum06 and W126 indices, utilize maximum hourly concentrations to identify risk assessment thresholds. The project's influence on O_3 concentrations is negligible and will not result in any foliar damage resulting from increases in O_3 concentrations.

7.5.3.6 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.

7.5.4 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 NO_2 and particulates, which are reported to cause physiological changes, are shown in Table 7-2. These values are up to orders of magnitude larger than maximum predicted concentrations for the Class I area. No effects on wildlife AQRVs from NO_2 and particulates are expected. The Project's contribution to cumulative impacts is negligible.

7.5.5 Total Nitrogen Deposition

As part of the AQRV analyses, total nitrogen (N) deposition rates were predicted at the Chassahowitzka NWA Class I area. The deposition analysis thresholds (DAT) are based on the annual averaging period. The total deposition is estimated in units of kilogram per hectare per year (kg/ha/yr) of nitrogen. The CALPUFF model (Version 5.8) was used to predict wet and dry deposition fluxes of various oxides of these elements.

For N deposition, the species include:

- Particulate ammonium nitrate (from species NO_3), wet and dry deposition;
- Nitric acid (species HNO_3), wet and dry deposition;
- NO_x, dry deposition; and
- Ammonium sulfate (species SO_4), wet and dry deposition.

The CALPUFF model produces results in units of $\mu g/m^2/s$. The modeled deposition rates are then converted to N deposition in kg/ha by using a multiplier equal to the ratio of the molecular weights of the substances (IWAQM Phase II Report, Section 3.3).

Deposition analysis thresholds (DAT) for nitrogen deposition of 0.01 kg/ha/yr were provided by the U.S. Fish and Wildlife Service (USFWS) (January 2002). A DAT is the additional amount of N deposition within a Class I area, below which estimated impacts from a new or modified source are considered insignificant. The maximum N depositions predicted for the project are, therefore, compared to these DAT or significant impact levels.

7.5.6 Results

The maximum predicted N depositions predicted for the project in the PSD Class I area of the Chassahowitzka NWA are summarized in Table 7-3. The maximum annual N deposition rates for the project at the Chassahowitzka NWA are predicted to be well below the N significant impact level of 0.01 kg/ha/yr.

7.5.7 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.

An analysis to determine the potential adverse plume visibility effects in the Chassahowitzka NWA was conducted 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 by FDEP and EPA to assess visual plume impacts in regulatory applications at Class I areas located within 50 km from a project site. The Chassahowitzka NWA Class I area is located entirely between 28 and 46 km from the proposed project site. 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), and 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 NO_2, soot, and primary sulfate. For this analysis, the Project's H_2SO_4 emissions were included as 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 200 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 fuel oil, 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 7-17 and 7-18. 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 20°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 background visual range was assumed to be 178 km based on information provided by the *Federal Land Manager's Air Quality Related Values Workgroup (FLAG), Phase I Report (December, 2000).* The background visual range is equivalent to a reference level of 22.0 inverse Mega-meters (Mm^{-1}) presented in Table 2.B-1 of Appendix 2.B of the FLAG document. Other parameters input to the model were based upon default values given in the Workbook and incorporated into the computer model.

As shown in Figures 7-17 and 7-18, the project's emissions due to natural gas- and oil-firing are calculated to exceed the Level 1 visibility screening criteria at the Class I area. Because results from the Level 1 screening analysis exceed the visibility criteria, a Level 2 screening analysis was performed. One of the main differences in input between the Level 1 and Level 2 analyses is the meteorology assumed for plume transport and dispersion patterns.

The Level 2 screening analysis is designed to account for more realistic occurrences of meteorological conditions that would transport the plumes of the proposed units towards the Class I area. In this analysis, an assessment of the frequency of the wind direction, wind speed, and atmospheric stability classes is made to determine the frequency of conditions that are most likely to cause a potentially adverse plume visual impact. If the Level 1 default parameters are selected for addressing visual plume impacts, the VISCREEN model assigns an appropriate estimate of particle size and density for the emitted and background atmosphere particulate and worst-case plume dispersion conditions. For this analysis, the particle size and density for the emission sources were not changed.

The first step in the analysis is to construct a table that shows worst-case dispersion conditions ranked in order of decreasing severity and the frequency of occurrence of these conditions associated with the wind direction that could transport emissions toward the Class I area. Dispersion conditions are ranked by evaluating the product of the horizontal dispersion parameter (called sigma y) times the vertical dispersion parameter (called sigma z) times the wind speed. Sigma y and sigma z account for the amount of plume spreading or dispersion that will occur as a plume travels away from a source for a given stability class. The dispersion conditions are then ranked in ascending order of the value of the dispersion product term (i.e., sigma y times sigma z times the wind speed).

For the Level 2 analysis, it is assumed that steady-state plume conditions are unlikely to persist for more than 12 hours. Thus, if a transit time of more than 12 hours is required to transport a plume parcel from the emission source to a Class I area for a given dispersion condition, it is assumed that the plume material is more dispersed than a standard Gaussian plume model would predict. This enhanced dilution would result from daytime convective mixing and wind direction and speed changes.

To obtain the worst-case meteorological conditions, it is necessary to determine the dispersion conditions (i.e., a given wind speed and stability class associated with the wind direction that would transport emissions toward the Class I area) that has a dispersion product term with a cumulative probability of 1 percent. Thus, the dispersion condition is selected to address potential plume visual impacts such that the sum of all frequencies of occurrence worse than this condition totals one percent (i.e., about 4 days per year). The one percentile meteorology is assumed to be worst-case plume visual impacts when the probability of worst-case meteorology conditions is coupled with the probability of other factors being ideal for maximizing plume visual impacts. Dispersion conditions associated with transport times of more than 12 hours are not considered in this cumulative frequency.

For this study, the surface meteorological data from the NWS station in Tampa from 2001 to 2005 were used to generate a frequency distribution of wind direction, wind speed, and stability occurrences based on the standardized stability array (STAR) program used for many air dispersion model applications. The STAR program generates frequencies using 16 wind direction classes with each class covering a 22.5-degree sector, 6 wind speed classes, and 6 stability classes. It should be noted that the 2001 to 2005 period of record was also used to address air quality impacts from the project as presented in Section 6.0.

The PSD Class I area of the Chassahowitzka NWA is located mostly within a 22.5-degree wind direction sector that is located north-northwest of the project site at distances that vary from approximately 28 km to 46 km. A much smaller portion of the NWA (less than five percent) that is not located within this wind direction sector but is within an adjacent wind direction sector that extends due north of the site. The frequencies associated with these two wind direction sectors were included in the analysis (i.e., south and south-southeast winds) with the average frequencies of the two wind direction sectors 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 period corresponding to the 12-hour period from 7 a.m. to 7 p.m. to 7 a.m.

This analysis is presented in Table 7-4, which shows the dispersion product term, transport time to the nearest part of the Class I area (i.e., distance of 28.0 km), and the frequency associated with each wind direction. As indicated in Table 7-4, 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 7-4, the average weather conditions for the daytime period when the CTs are likely to operate, neutral (D class) stability and a wind speed of 4.4 m/s, are 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, 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.

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 2.89 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.

TABLE 7-1
MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED
FOR THE PROPOSED PROJECT FIRING ULTRA-LOW SULFUR FUEL OIL
FOR AQRV ANALYSIS

Pollutant	Averaging Time	Maximum Concentrations [a] (ug/m^3)
2 CTs and Fuel Heater [e]		
PM_{10}	Annual [b]	0.003
	24-Hour	0.029
	8-Hour	0.063
	3-Hour	0.139
	1-Hour	0.343
NO_2	Annual [c, d]	0.007
	24-Hour	0.47
	8-Hour	1.14
	3-Hour	2.53
	1-Hour	5.93
CO	Annual [b]	0.011
	24-Hour	0.11
	8-Hour	0.24
	3-Hour	0.53
	1-Hour	1.30

[a] Concentrations are based on highest predicted concentrations from AERMOD using five years of meteorological data for 2001 to 2005 consisting of surface and upper air data from the National Weather Service stations at Tampa International Airport and Ruskin, respectively.

[b] As a conservative approach, annual concentrations for PM_{10} and CO based on CTs firing fuel oil for full year

[c] Annual concentration for NO_2 based on CTs firing gas for 2390 hours and oil for 1000 hours per year.

[d] NO_x to NO_2 conversion factor of 0.75 applied to modeled NO_x impacts based on EPA Modeling Guidelines

[e] Based on base load 20 °F for NO_2 and CO and 50% load, 95 °F for PM_{10}

TABLE 7-2

EXAMPLES OF REPORTED EFFECTS OF AIR POLLUTANTS AT CONCENTRATIONS BELOW NATIONAL SECONDARY AMBIENT AIR QUALITY STANDARDS

Pollutant	Reported Effect	Concentration ($\mu g/m^3$)	Exposure
Sulfur Dioxide[a]	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[b,c]	Respiratory stress in mice	1,917	3 hours
	Respiratory stress in guinea pigs	96 to 958	8 hours/day for 122 days
Particulates[a]	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

Sources: [a] Newman and Schreiber, 1988.
[b] Gardner and Graham, 1976.
[c] Trzeciak et al., 1977.

TABLE 7-3
MAXIMUM ANNUAL NITROGEN DEPOSITION PREDICTED
FOR THE PROPOSED PROJECT AT THE CHASSAHOWITZKA NWA

Species	Total Deposition (Wet & Dry)		Year	Deposition Analysis Threshold [b]
	($g/m^2/s$)	(kg/ha/yr)[a]		(kg/ha/yr)
Nitrogen (N) Deposition	9.39E-12	0.0030	2001	0.01
	9.62E-12	0.0030	2002	
	1.21E-11	0.0038	2003	

[a] Conversion factor is used to convert $g/m^2/s$ to kg/hectare (ha)/yr with the following units:

$g/m^2/s$ x 0.001 kg/g
x 10,000 m^2/hectare
x 3,600 sec/hr
x 8,760 hr/yr = kg/ha/yr
or
$g/m^2/s$ x 3.154E+08 = kg/ha/yr

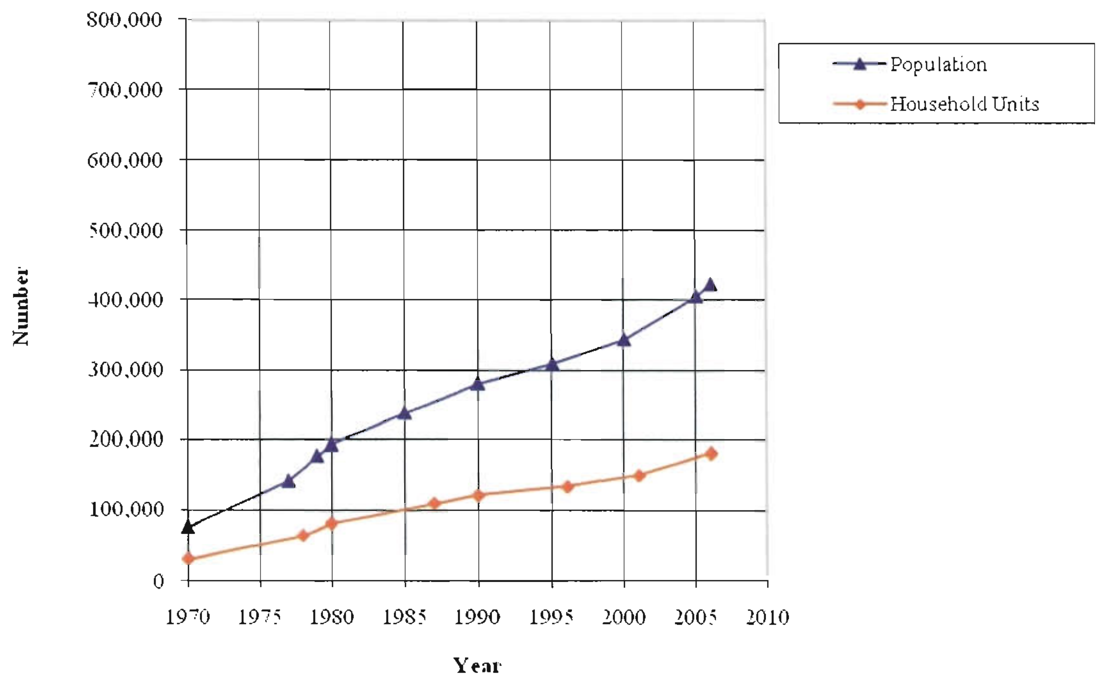
[b] Deposition analysis thresholds (DAT) for nitrogen deposition provided by the U.S. Fish and Wildlife Service. January 2002. A DAT is the additional amount of N or S deposition within a Class I area, below which estimated impacts from a propsed new or modified source are considered insignificant.

TABLE 7-4
PLUME VISUAL IMPACT ANALYSIS - SCREENING LEVEL 2 - IDENTIFICATION OF WORSE-CASE METEOROLOGICAL CONDITIONS

Dispersion Conditions						Transport Time to Class I Area (hours) [a]	Frequency of Occurrence (percent) of Dispersion Conditions [c]			
Stability		Wind Speed (m/s)	Dispersion Parameter		Sigma Y x Sigma Z x Wind Speed (m^3/s)		7 a.m. to 1 p.m.		1 p.m. to 7 p.m.	
Category	Name		Horizontal (sigma Y (m))	Vertical (sigma Z (m))			f [b]	cf [b]	f [b]	cf [b]
Combined South-southeast to South Wind Direction Sector [d]										
F	Moderately Stable	0.8	673.6	67.3	36,267	9.7	0.02	0.02	0.11	0.11
E	Slightly Stable	0.8	1011.5	124.1	100,378	9.7	0.00	0.02	0.00	0.11
F	Moderately Stable	2.6	673.6	67.3	117,867	3.0	0.04	0.05	0.12	0.23
F	Moderately Stable	4.4	673.6	67.3	199,467	1.8	0.00	0.05	0.00	0.23
D	Neutral	0.8	1,350.7	241.5	261,002	9.7	0.02	0.08	0.01	0.34
E	Slightly Stable	2.6	1011.5	124.1	326,230	3.0	0.01	0.09	0.29	0.53
E	Slightly Stable	4.4	1011.5	124.1	552,081	1.8	0.00	0.09	0.10	0.63
D	Neutral	2.6	1350.7	241.5	848,257	3.0	0.42	0.52	0.29	0.92
D	Neutral	4.4	1350.7	241.5	1,435,512	1.8	0.65	1.16	0.66	1.58
South-southeast Wind Direction Sector Only										
F	Moderately Stable	0.8	673.6	67.3	36,267	9.7	0.01	0.01	0.01	0.01
E	Slightly Stable	0.8	1011.5	124.1	100,378	9.7	0.00	0.01	0.00	0.01
F	Moderately Stable	2.6	673.6	67.3	117,867	3.0	0.05	0.05	0.04	0.05
F	Moderately Stable	4.4	673.6	67.3	199,467	1.8	0.00	0.05	0.00	0.05
D	Neutral	0.8	1,350.7	241.5	261,002	9.7	0.02	0.07	0.02	0.06
E	Slightly Stable	2.6	1011.5	124.1	326,230	3.0	0.02	0.09	0.15	0.21
E	Slightly Stable	4.4	1011.5	124.1	552,081	1.8	0.00	0.09	0.01	0.22
D	Neutral	2.6	1,350.7	241.5	848,257	3.0	0.32	0.41	0.15	0.37
D	Neutral	4.4	1350.7	241.5	1,435,512	1.8	0.42	0.83	0.37	0.73
South Wind Direction Sector Only										
F	Moderately Stable	0.8	673.6	67.3	36,267	9.7	0.03	0.03	0.22	0.22
E	Slightly Stable	0.8	1011.5	124.1	100,378	9.7	0.00	0.03	0.00	0.22
F	Moderately Stable	2.6	673.6	67.3	117,867	3.0	0.03	0.05	0.20	0.42
F	Moderately Stable	4.4	673.6	67.3	199,467	1.8	0.00	0.05	0.00	0.42
D	Neutral	0.8	1,350.7	241.5	261,002	9.7	0.03	0.08	0.00	0.42
E	Slightly Stable	2.6	1011.5	124.1	326,230	3.0	0.00	0.08	0.44	0.86
E	Slightly Stable	4.4	1011.5	124.1	552,081	1.8	0.01	0.09	0.18	1.04
D	Neutral	2.6	1350.7	241.5	848,257	3.0	0.53	0.62	0.43	1.47
D	Neutral	4.4	1350.7	241.5	1,435,512	1.8	0.88	1.50	0.96	2.43

[a] Proposed project location is approximately 28.0 km from closest boundary of Class I area.
[b] f= frequency for given meteorological condition; cf= cumulative frequency up to and including condition.
[c] Based on surface meteorological data for 2001 to 2005 from the National Weather Service (NWS) station at the Tampa International Airport.
[d] Approximately 95 percent of the Chassahowitzka NWA is downwind of the proposed project with a south-southeast wind direction.

Figure 7-1. Population and Household Unit Trends in Pasco County



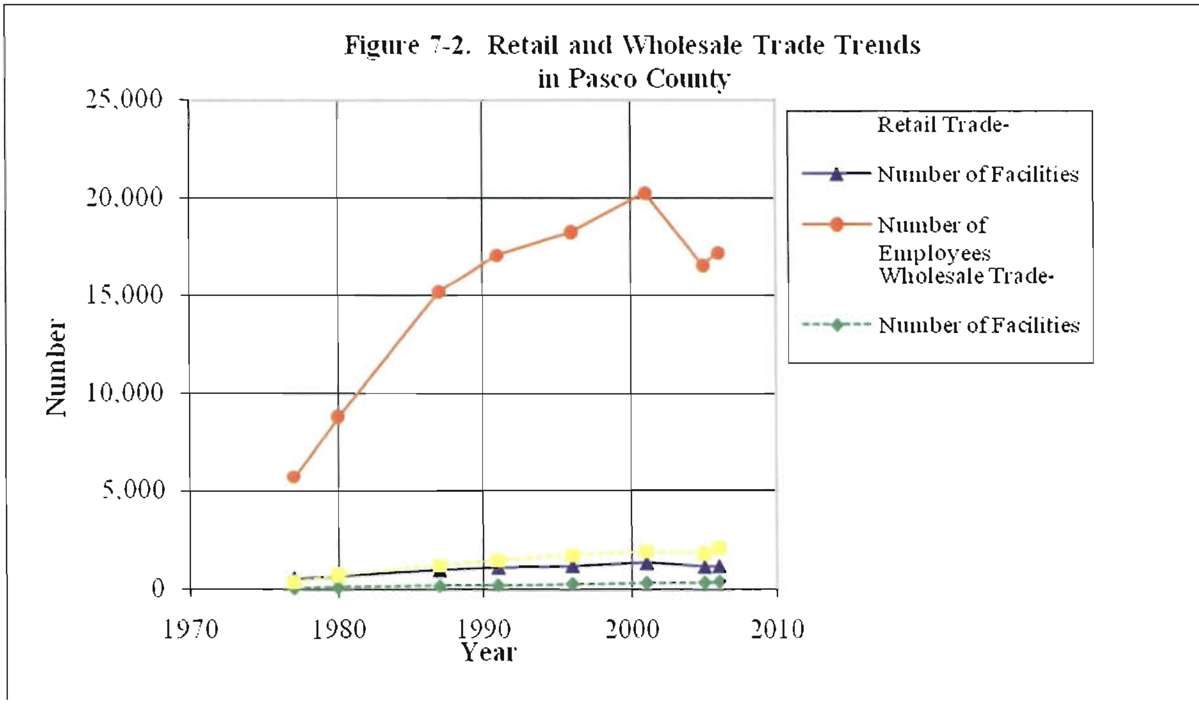


Figure 7-2. Retail and Wholesale Trade Trends in Pasco County
25,000
20,000
15,000
10,000
5,000
0
Number
1970
1980
1990
2000
2010
Year
Retail Trade-
Number of Facilities
Number of Employees
Wholesale Trade-
Number of Facilities

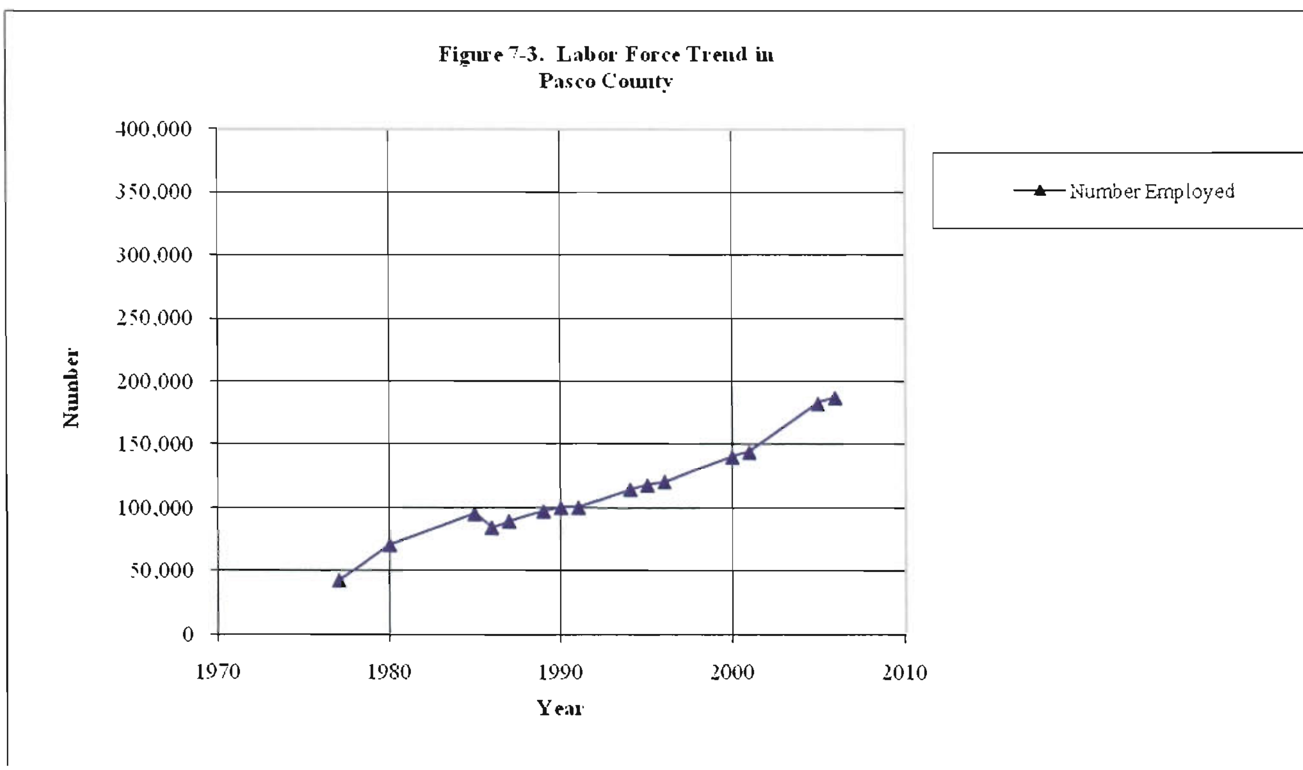


Figure 7-3. Labor Force Trend in Pasco County
400,000
350,000
300,000
250,000
200,000
150,000
100,000
50,000
0
Number
1970
1980
1990
2000
2010
Year
Number Employed

Figure 7-4. Hotel and Motel Trends in Pasco County

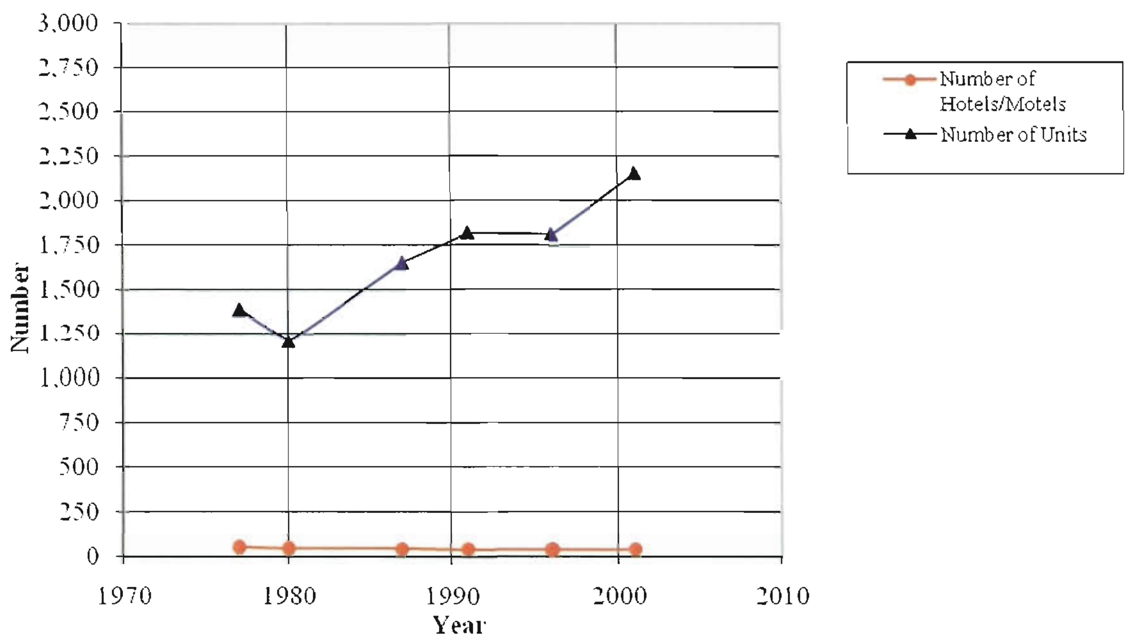
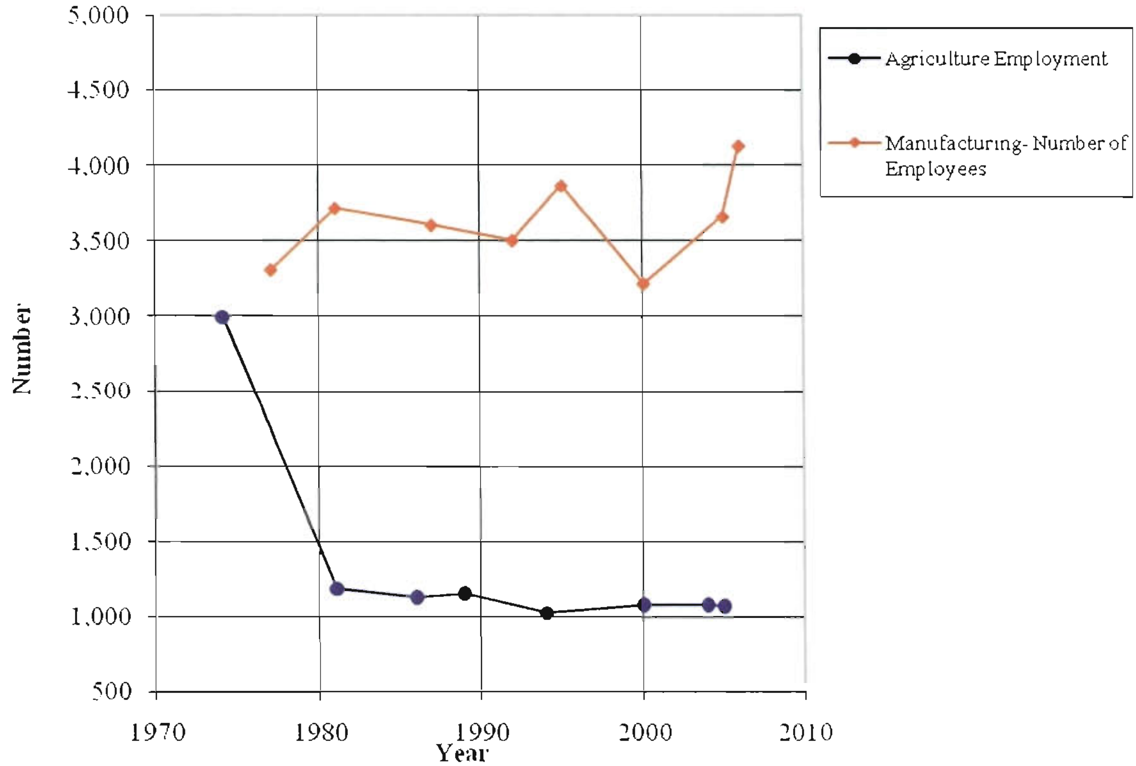


Figure 7-5. Manufacturing and Agriculture Trends in Pasco County



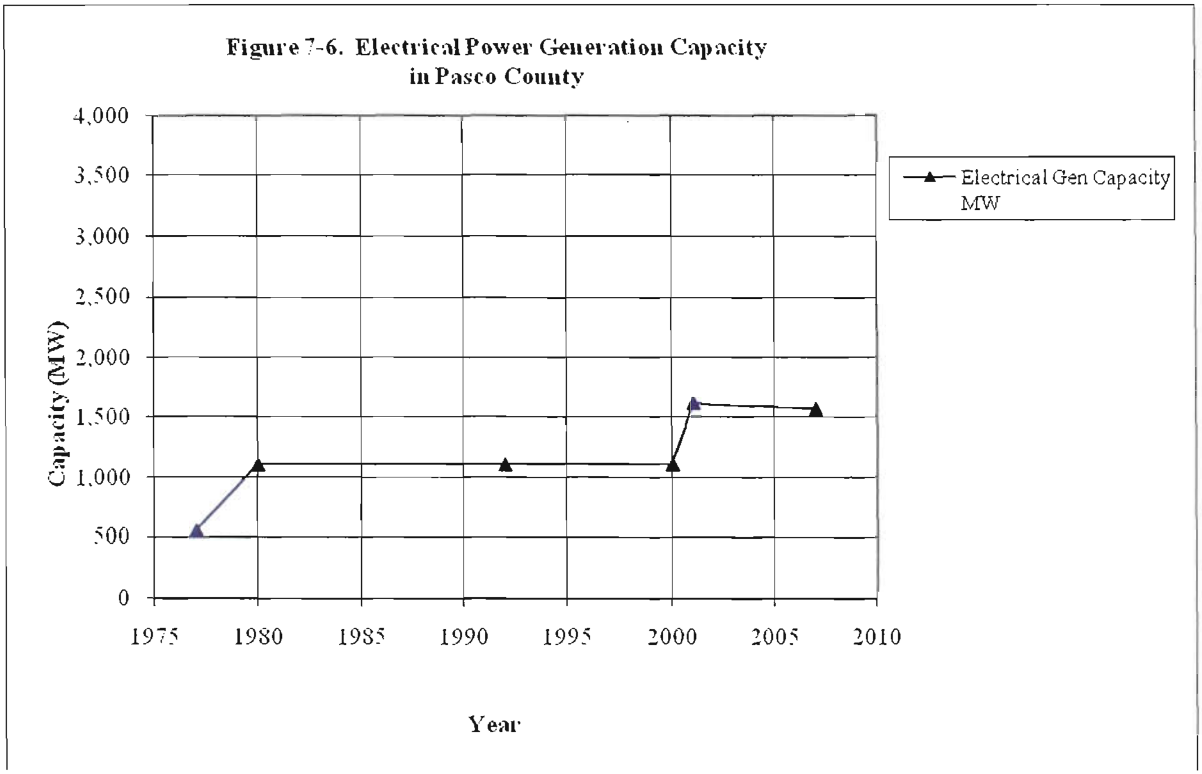


Figure 7-6. Electrical Power Generation Capacity
in Pasco County
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Capacity (MW)
1975
1980
1985
1990
1995
2000
2005
2010
Year
Electrical Gen Capacity MW

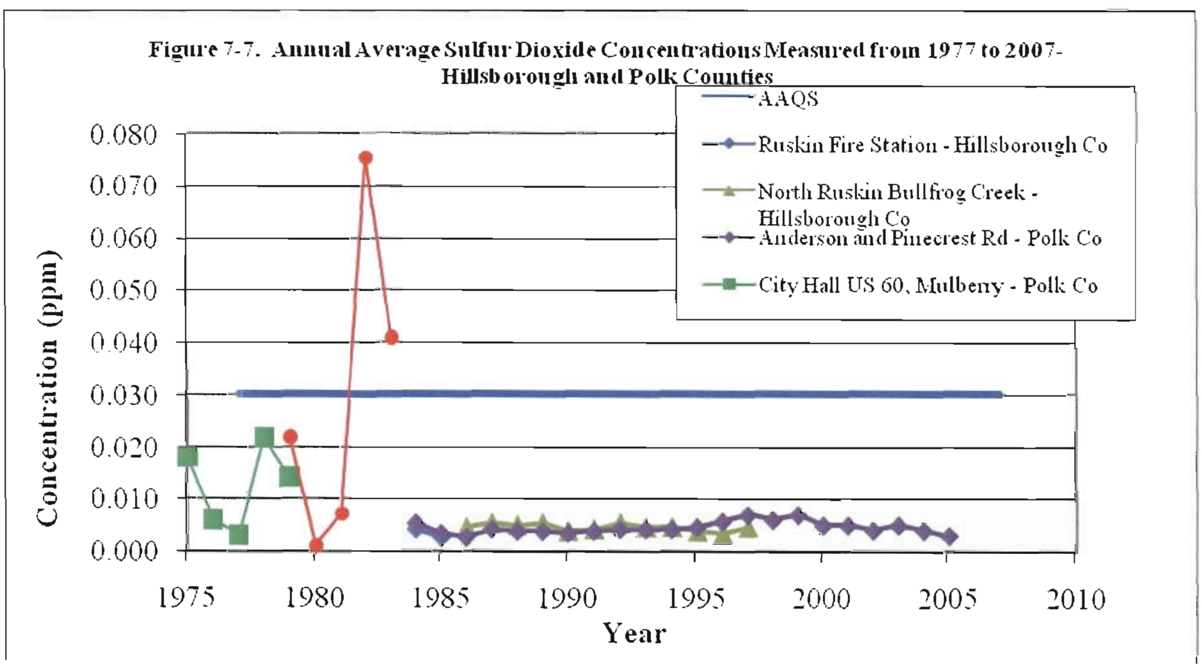


Figure 7-7. Annual Average Sulfur Dioxide Concentrations Measured from 1977 to 2007-
Hillsborough and Polk Counties
AAQS
Ruskin Fire Station - Hillsborough Co
North Ruskin Bullfrog Creek - Hillsborough Co
Anderson and Pinecrest Rd - Polk Co
City Hall US 60, Mulberry - Polk Co
0.080
0.070
0.060
0.050
0.040
0.030
0.020
0.010
0.000
Concentration (ppm)
1975
1980
1985
1990
1995
2000
2005
2010
Year

Figure 7-8. 24-hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured from 1977 to 2007- Hillsborough and Polk Counties

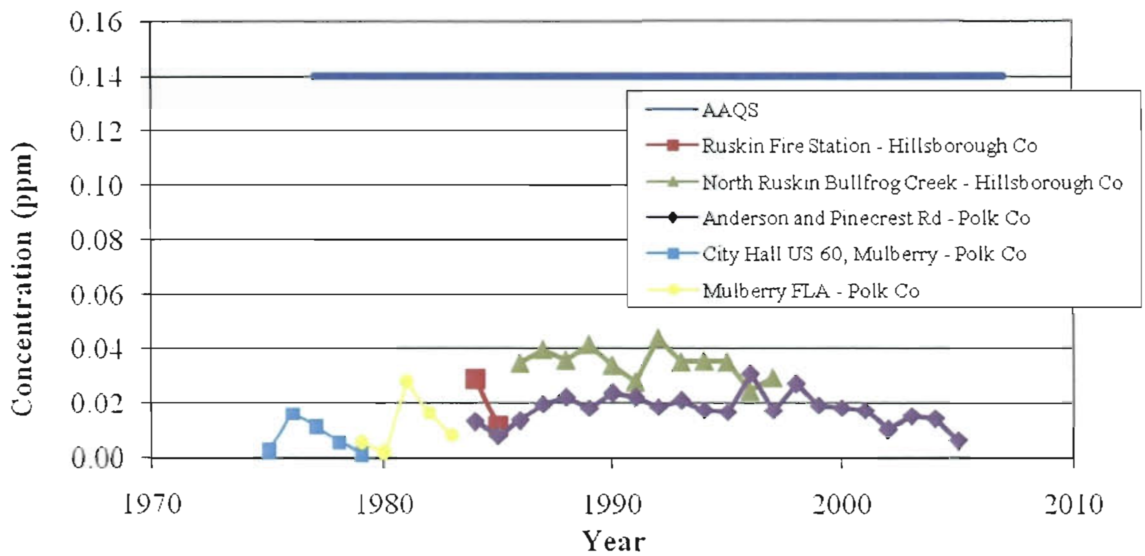


Figure 7-9. 3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) Measured from 1977 to 2007- Hillsborough and Polk Counties

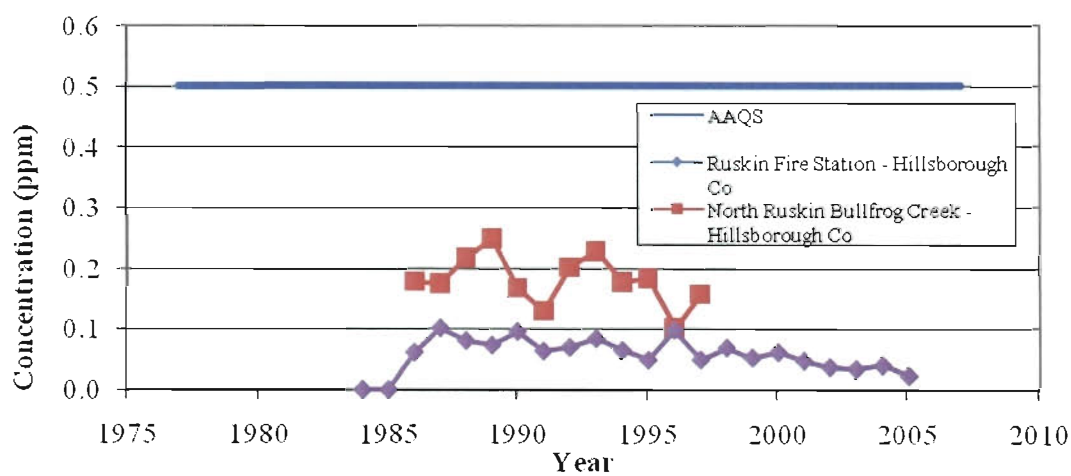


Figure 7-10. Annual Average PM_{10} Concentrations and TSP Concentrations Measured from 1977 to 2007- Hillsborough and Polk Counties

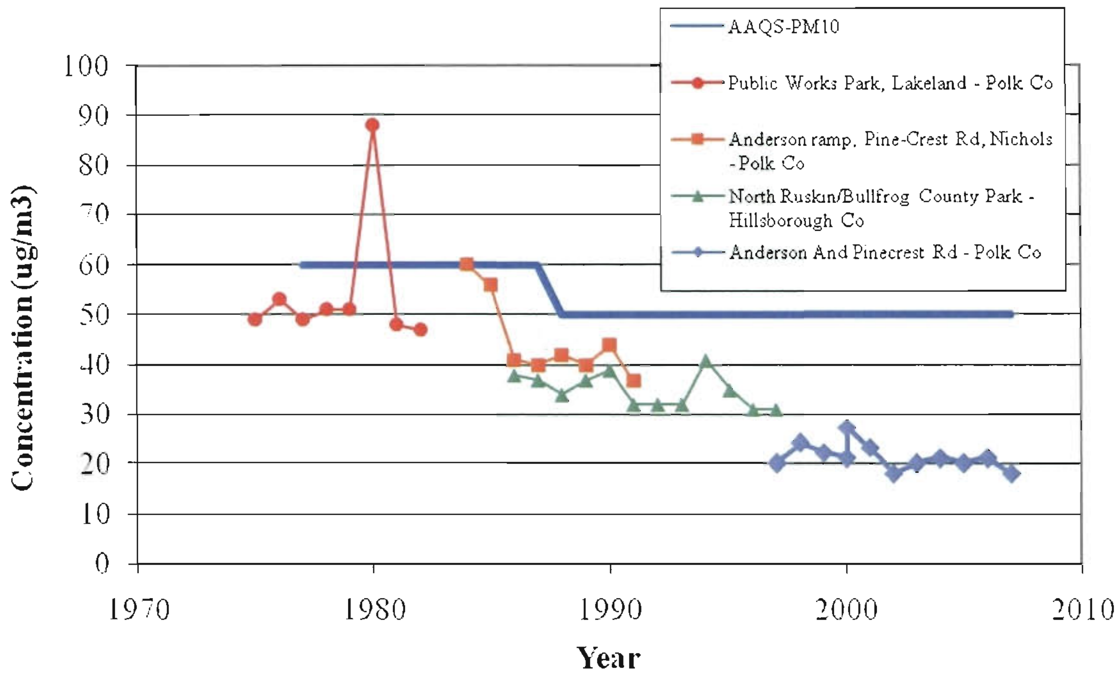


Figure 7-11. 24-hour Average PM_{10} Concentrations and TSP Concentrations (2[nd] Highest Values) Measured from 1977 to 2007 Hillsborough and Polk Counties

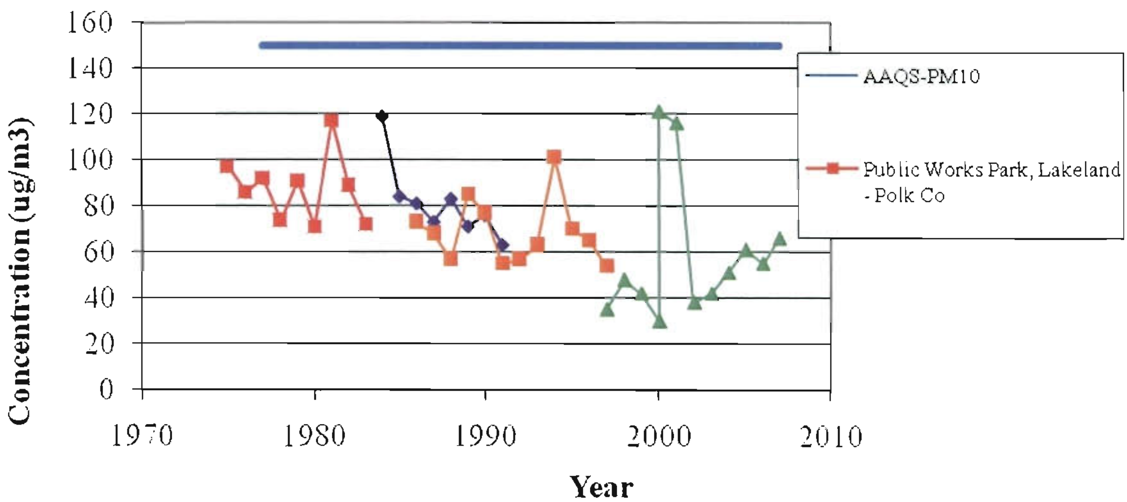


Figure 7-12. Measured Annual Average Nitrogen Dioxide Concentrations from 1977 to 2007- Hillsborough and Polk Counties

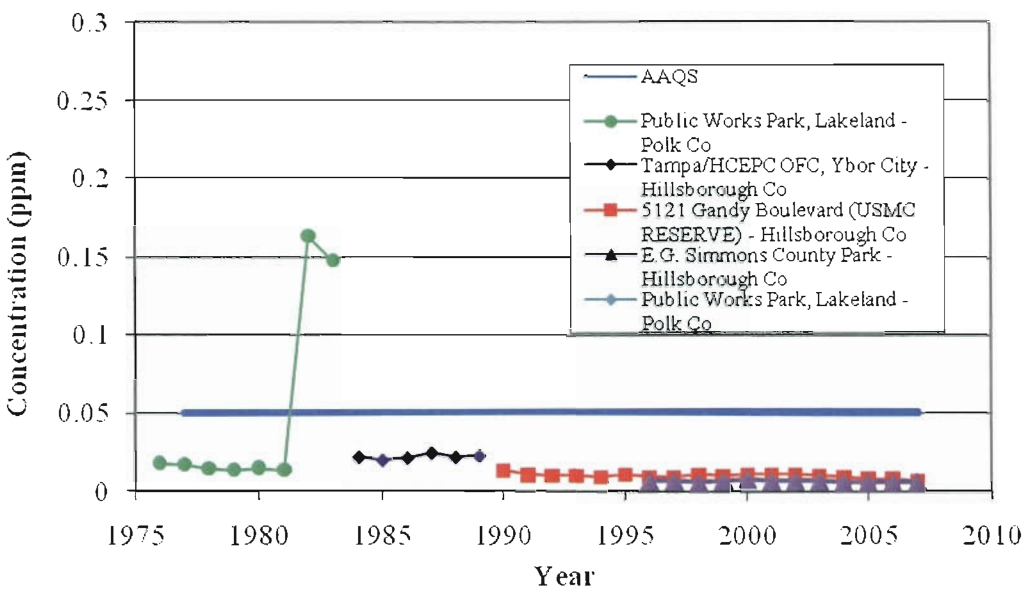


Figure 7-13. 8-hour Average Carbon Monoxide Concentrations (2nd Highest Values) Measured from 1977 to 2007- Hillsborough and Pinellas Counties

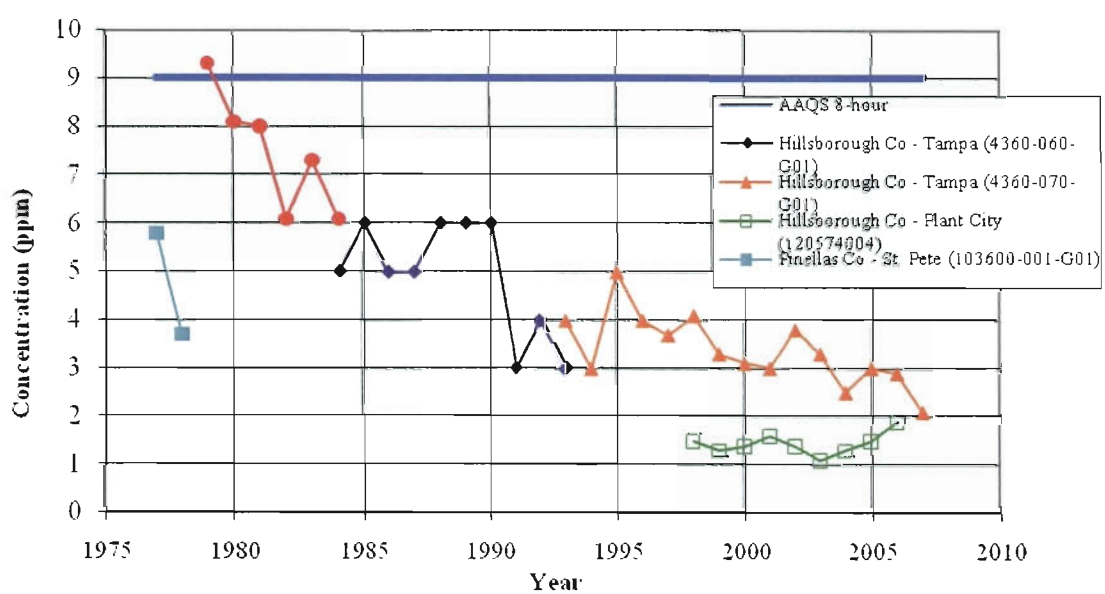


Figure 7-14. 8-hour Average Carbon Monoxide Concentrations (2nd Highest Values) Measured from 1977 to 2007- Hillsborough and Pinellas Counties

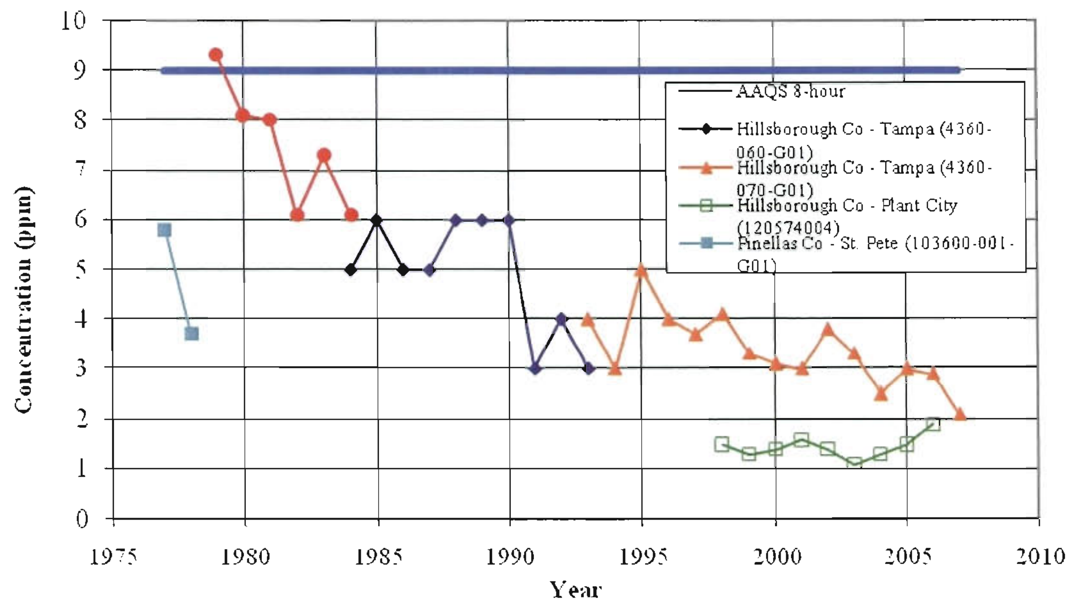


Figure 7-15. 1-hour Average Ozone Concentrations (2nd Highest Values) Measured from 1977 to 2007- Pinellas, Pasco and Hillsborough Counties

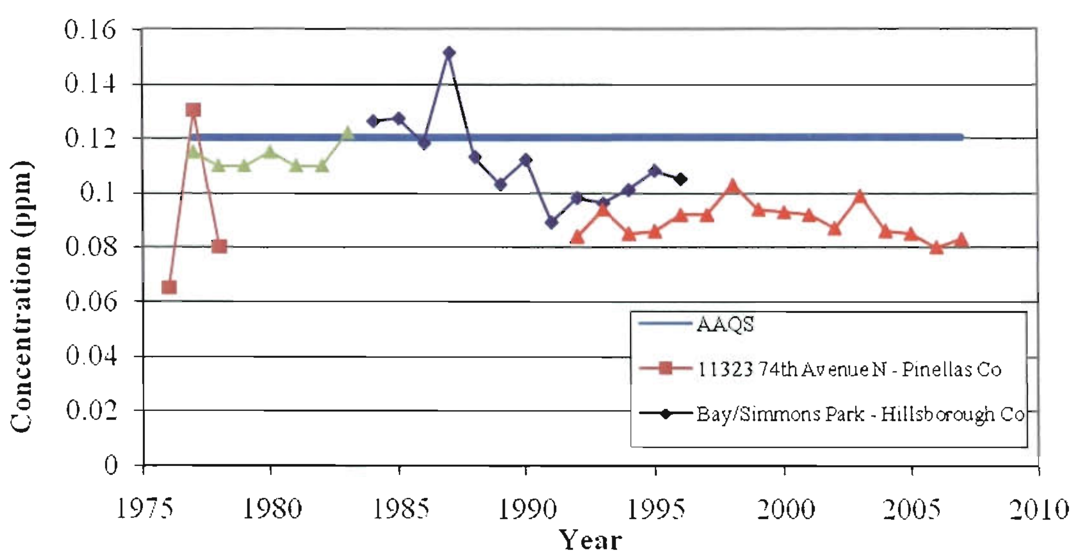


Figure 7-16. 8-hour Average Ozone Concentrations (3-year Average of the 4th Highest Values) Measured from 1997 to 2007- Pasco County

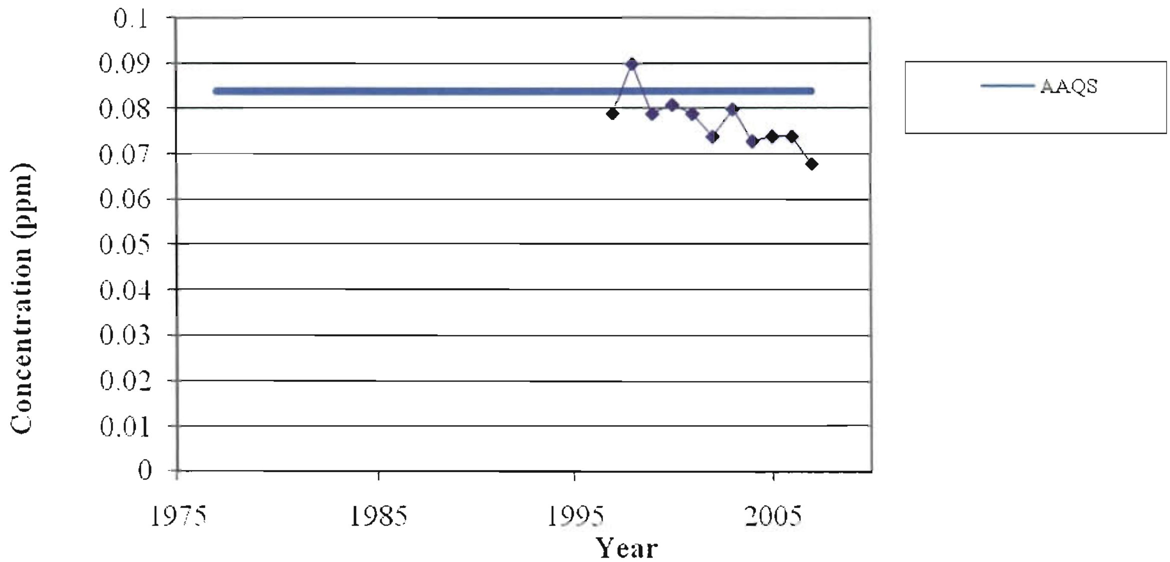


Figure 7-17 Level 1 Screening Analysis of Visual Effects due to the Project Firing Natural Gas Predicted at the Chassahowitzka NWA

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

  Particulates   18.00  LB /HR
  NOx (as NO2)    129.10  LB /HR
  Primary NO2      .00  LB /HR
  Soot          .00  LB /HR
  Primary SO4     3.28  LB /HR


  **** Default Particle Characteristics Assumed

        Transport Scenario Specifications:

  Background Ozone:              .04 ppm
  Background Visual Range:        177.80 km
  Source-Observer Distance:      28.0 km
  Min. Source-Class I Distance:   28.0 km
  Max. Source-Class I Distance:   46/0 km
  Plume-Source-Observer Angle:    11.25 degrees
  Stability:  6
  Wind Speed:  1.00 m/s

                RESULTS

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. 152.  46.0   16.  2.00 4.470*  .05  .047
 SKY    140. 152.  46.0   16.  2.00 2.921*  .05 -.059


     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 18.435*  .05  .374*
 SKY    140.  0.   1.0  168.  2.00 6.167*  .05 -.210*
```

Figure 7-18 Level 1 Screening Analysis of Visual Effects due to the Project Firing Fuel Oil Predicted at the Chassahowitzka NWA

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

 Particulates   34.00 LB /HR
 NOx (as NO2)  693.70 LB /HR
 Primary NO2      .00 LB /HR
 Soot             .00 LB /HR
 Primary SO4     0.98 LB /HR


  **** Default Particle Characteristics Assumed

         Transport Scenario Specifications:

  Background Ozone:               .04 ppm
  Background Visual Range:      177.80 km
  Source-Observer Distance:      28.00 km
  Min. Source-Class I Distance:  28.00 km
  Max. Source-Class I Distance:  46.00 km
  Plume-Source-Observer Angle:   11.25 degrees
  Stability:  6
  Wind Speed:  1.00 m/s

              R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

     Maximum Visual Impacts INSIDE  Class I Area
       Screening Criteria ARE Exceeded
                         Delta E      Contrast
                       ===========  ===========
Backgrnd Theta Azi Distance Alpha Crit  Plume   Crit  Plume
======== ===== === ======== ===== ==== =====  ==== =====
 SKY     10.  145.   39.9   24.  2.00 18.489*  .05  -.023
 SKY    140.  145.   39.9   24.  2.00 11.730*  .05  -.144*

     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 27.758*  .05  -.443*
 SKY    140.    0.    1.0  168.  2.00  8.224*  .05  -.274*
```

Figure 7-19 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 18.00 LB /HR
NOx (as NO2) 129.10 LB /HR
Primary NO2 .00 LB /HR
Soot .00 LB /HR
Primary SO4 3.28 LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone: .04 ppm
Background Visual Range: 177.80 km
Source-Observer Distance: 28.0 km
Min. Source-Class I Distance: 28.0 km
Max. Source-Class I Distance: 46/0 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

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	152.	46.0	16.	2.00	.290	.05	.003
SKY	140.	152.	46.0	16.	2.00	.199	.05	-.004

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	0.	1.0	168.	2.00	2.894*	.05	.039
SKY	140.	0.	1.0	168.	2.00	1.397	.05	-.038

Figure 7-20 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 34.00 LB /HR
NOx (as NO2) 693.70 LB /HR
Primary NO2 .00 LB /HR
Soot .00 LB /HR
Primary SO4 0.98 LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone: .04 ppm
Background Visual Range: 177.80 km
Source-Observer Distance: 28.00 km
Min. Source-Class I Distance: 28.00 km
Max. Source-Class I Distance: 46.00 km
Plume-Source-Observer Angle: 11.25 degrees
Stability: 4
Wind Speed: 4.40 m/s

RESULTS

Asterisks (*) indicate plume impacts that exceed screening criteria

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

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	152.	46.0	16.	2.00	1.543	.05	-.002
SKY	140.	152.	46.0	16.	2.00	.966	.05	-.011

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	0.	1.0	168.	2.00	4.880*	.05	-.055*
SKY	140.	0.	1.0	168.	2.00	1.995	.05	-.050*

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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MAY 13 2008

BUREAU OF AIR REGULATION

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Shady Hills Power Company, LLC**	
2. Site Name: **Shady Hills Generating Station**	
3. Facility Identification Number: **1010373**	
4. Facility Location...: Street Address or Other Locator: **14240 Merchant Energy Way** City: **Spring Hill** County: **Pasco** Zip Code: **34610**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Roy S. Belden**
2. Application Contact Mailing Address... Organization/Firm: **Shady Hills Power Company, LLC** Street Address: **120 Long Ridge Rd.** City: **Stamford** State: **CT** Zip Code: **06927**
3. Application Contact Telephone Numbers... Telephone: **(203) 357-6820** ext. Fax: **(203) 961-5116**
4. Application Contact Email Address: **Roy.Belden@GE.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 5/13/08	3. PSD Number (if applicable): 402
2. Project Number(s): 1010373-007-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

The project will consist of two General Electric Frame 7FA CTs (GE 7FA) and associated facilities. The GE 7FA units will each be equipped with evaporative cooling. The annual maximum capacity factor of the plant will be 39 percent, which is equivalent to operating 3,390 hours/year at full load per CT. 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/year at full load per CT. No single combustion turbine will operate more than 5,000 hours in a single year. The project will require an additional gas heater for the two new CTs. In addition, since the present generator is marginally rated, there will be a need to increase the size of the emergency diesel/generator to 2,250 kW to accommodate the additional CTs.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
005	170-MW Simple-Cycle Combustion Turbine	AC1A	
006	170-MW Simple-Cycle Combustion Turbine	AC1A	
007	Emergency Generator	AC1A	
008	Natural Gas Heater	AC1A	

Application Processing Fee

Check one: ☒ Attached - Amount: $____**7,500.00**__________ ☐ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : Roy S. Belden
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Shady Hills Power Company, LLC** Street Address: **120 Long Ridge Rd.** City: **Stamford** State: **CT** Zip Code: **06927**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(203) 357 - 6820** ext. Fax: **(203) 961 - 5116**
4.	Owner/Authorized Representative Email Address: **Roy.Belden@GE.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Roy S. Belden — May 2, 2008 Signature — Date

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: () - ext. Fax: () -
5. Application Responsible Official Email Address:
6. Application Responsible Official Certification: *I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.* Signature Date

Professional Engineer Certification

1.	Professional Engineer Name: **Scott H. Osbourn** Registration Number: **57557**
2.	Professional Engineer Mailing Address... Organization/Firm: **Golder Associates Inc.**** Street Address: **5100 West Lemon St., Suite 114** City: **Tampa** State: **FL** Zip Code: **33609**
3.	Professional Engineer Telephone Numbers... Telephone: **(813) 287-1717** ext.**53304** Fax: **(813) 287-1716**
4.	Professional Engineer Email Address: **sosbourn@golder.com**
5.	Professional Engineer Statement: *I, the undersigned, hereby certify, except as particularly noted herein*, that:* *(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and* *(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.* *(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.* *(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.* *(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.* Scott Osbourn Signature 5/9/08 Date (seal) SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* **Attach any exception to certification statement.**
** **Board of Professional Engineers Certificate of Authorization # 00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **347.0** North (km) **3,139.0**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **28/22/00** Longitude (DD/MM/SS) **82/30/00**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Roy S. Belden, Vice President**
2. Facility Contact Mailing Address... Organization/Firm: **Shady Hills Power Company, LLC** Street Address: **120 Long Ridge Rd.** City: **Stamford** State: **CT** Zip Code: **06927**
3. Facility Contact Telephone Numbers: Telephone: **(203) 357-6820** ext. Fax: **(203) 961-5116**
4. Facility Contact Email Address: **Roy.Belden@GE.com**

Facility Primary Responsible Official

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

~~1. Facility Primary Responsible Official Name:~~ **Roy S. Belden**
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: **Shady Hills Power Company, LLC** Street Address: **120 Long Ridge Rd.** City: **Stamford** State: **CT** Zip Code: **06927**
3. Facility Primary Responsible Official Telephone Numbers... Telephone: **(203) 357-6820** ext. Fax: **(203) 961-5116**
4. Facility Primary Responsible Official Email Address: **Roy.Belden@GE.com**

Facility Regulatory Classifications

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

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **Emissions units 005, and 006 are subject to NSPS Subpart KKKK - Standards of Performance for Stationary Gas Turbines.** **Emergency Generator subject to NSPS Subpart IIII.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM_{10}	A	N
CO	A	N
VOC	A	N
SO_2	A	N
NO_x	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☐ Attached, Document ID: **NA**
3. Rule Applicability Analysis: ☒ Attached, Document ID: **See PSD Report**
4. List of Exempt Emissions Units: ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:____ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units: ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)	

Additional Requirements for Title V Air Operation Permit Applications – N/A

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

C. FACILITY ADDITIONAL INFORMATION

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

1.	Acid Rain Program Forms: Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)): ☒ Attached, Document ID: SH-FI-C1__ ☐ Previously Submitted, Date:________ ☐ Not Applicable (not an Acid Rain source) Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Not Applicable New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☐ Not Applicable
2.	CAIR Part (DEP Form No. 62-210.900(1)(b)): ☐ Attached, Document ID:SH-FI-C1__ ☐ Previously Submitted, Date:________ ☐ Not Applicable (not a CAIR source)
3.	Hg Budget Part (DEP Form No. 62-210.900(1)(c)): ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:________ ☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

The Certificate of Representative is included in SH-FI-C1, which indicateds the Designated Representative for the CAIR program. The CAIR application form will be submitted with the Title V revision application.

SH-FI-C1

Acid Rain Program Forms

Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30, 72.31, and 74; and Chapter 62-214, F.A.C.

This submission is: ■ New ☐ Revised ☐ Renewal

STEP 1

Identify the source by plant name, state, and ORIS or plant code.

Plant name **Shady Hills Generating Station**	State **FL**	**55414** ORIS/Plant Code

STEP 2
Enter the unit ID# for every Acid Rain unit at the Acid Rain source in column "a."

If unit a SO_2 Opt-in unit, enter "yes" in column "b".

For new units or SO_2 Opt-in units, enter the requested information in columns "d" and "e."

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
GT 401	**N**	**Yes**	**6/2010**	**12/2010**
GT 501	**N**	**Yes**	**6/2010**	**12/2010**
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

Plant Name (from STEP 1) **Shady Hills Generating Station**

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR Part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.
(4) For applications including a SO_2 Opt-in unit, a monitoring plan for each SO_2 Opt-in unit must be submitted with this application pursuant to 40 CFR 74.14(a). For renewal applications for SO_2 Opt-in units include an updated monitoring plan if applicable under 40 CFR 75.53(b).

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)), or in the compliance subaccount of another Acid Rain unit at the same source to the extent provided in 40 CFR 73.35(b)(3), not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000, or the deadline for monitor certification under 40 CFR Part 75, an Acid Rain unit under 40 CFR. 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain Part application, the Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the DEP:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

EP 3,
Continued.

Plant Name (from STEP 1) **Shady Hills Generating Station**

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_X averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities.

No provision of the Acid Rain Program, an Acid Rain Part application, an Acid Rain Part, or an exemption under 40 CFR 72.7or 72.8 shall be construed as:
(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

STEP 4
For SO_2 Opt-in units only.

In column "f" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" of STEP 2.

For column "g" describe the combustion unit and attach information and diagrams on the combustion unit's configuration.

In column "h" enter the hours.

f	g	h (not required for renewal application)
Unit ID#	Description of the combustion unit	Number of hours unit operated in the six months preceding initial application

Plant Name (from STEP 1) **Shady Hills Generating Station**

STEP 5

For SO_2 Opt-in units only.
(Not required for SO_2 Opt-in renewal applications.)

In column "i" enter the unit ID# for every SO_2 Opt-in unit identified in column "a" (and in column "f").

For columns "j" through "n," enter the information required under 40 CFR 74.20-74.25 and attach all supporting documentation required by 40 CFR 74.20-74.25.

i	j	k	l	m	n
Unit ID#	Baseline or Alternative Baseline under 40 CFR 74.20 (mmBtu)	Actual SO_2 Emissions Rate under 40 CFR 74.22 (lbs/mmBtu)	Allowable 1985 SO_2 Emissions Rate under 40 CFR 74.23 (lbs/mmBtu)	Current Allowable SO_2 Emissions Rate under 40 CFR 74.24 (lbs/mmBtu)	Current Promulgated SO_2 Emissions Rate under 40 CFR 74.25 (lbs/mmBtu)

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

A. If the combustion source seeks to qualify for a transfer of allowances from the replacement of thermal energy, a thermal energy plan as provided in 40 CFR 74.47 for combustion sources must be attached.
B. A statement whether the combustion unit was previously an affected unit under 40 CFR 74.
C. A statement that the combustion unit is not an affected unit under 40 CFR 72.6 and does not have an exemption under 40 CFR 72.7, 72.8, or 72.14.
D. Attach a complete compliance plan for SO_2 under 40 CFR 72.40.
E. The designated representative of the combustion unit shall submit a monitoring plan in accordance with 40 CFR 74.61. For renewal application, submit an updated monitoring plan if applicable under 40 CFR 75.53(b).
F. The following statement must be signed by the designated representative or alternate designated representative of the combustion source: "I certify that the data submitted under 40 CFR Part 74, Subpart C, reflects actual operations of the combustion source and has not been adjusted in any way."

Signature | Date

STEP 7

Read the certification statement; provide name, title, owner company name, phone, and e-mail address; sign, and date.

Certification (for designated representative or alternate designated representative only)

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

Name **Mr. Roy S. Belden** | Title **Vice President**

Owner Company Name **Shady Hills Power Company, LLC, 120 Long Ridge Rd., Stamford, CT 06927**

Phone **(203) 357-6820** | E-mail address **Roy.Belden@GE.com**

Signature Roy S. Belden | Date May 7, 2008

EPA

Certificate of Representation

Page

For more information, see instructions and 40 CFR 72.24; 40 CFR 96.113, 96.213, or 96.313, or a comparable state regulation under the Clean Air Interstate Rule (CAIR) NO_X Annual, SO_2, and NO_X Ozone Season Trading Programs; 40 CFR 97.113, 97.213, or 97.313; or 40 CFR 60.4113, or a comparable state regulation under the Clean Air Mercury Rule (CAMR), as applicable.

This submission is: X New Revised (revised submissions must be complete; see instructions)

FACILITY (SOURCE) INFORMATION

STEP 1
Provide information for the facility (source).

Facility (Source) Name **Shady Hills Generating Station**	State **FL**	Plant Code **55414**
County Name **Pasco**		
Latitude **28.36**	Longitude **82.5**	

STEP 2
Enter requested information for the designated representative.

Name **Mr. Roy S. Belden**	Title **Vice President**
Company Name **Shady Hills Power Company, LLC**	
Address **120 Long Ridge Rd., Stamford, CT 06927**	
Phone Number **(203) 357-6820**	Fax Number **(203) 961-5116**
E-mail address **Roy.Belden@GE.com**	

STEP 3
Enter requested information for the alternate designated representative.

Name	Title
Company Name	
Address	
Phone Number	Fax Number
E-mail address	

Facility (Source) Name (from Step 1) **Shady Hills Generating Station**

UNIT INFORMATION

STEP 4: <u>Complete one page for each unit located at the facility identified in STEP 1</u> (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): X Acid Rain X CAIR NO_X Annual X CAIR SO_2 X CAIR NO_X Ozone Season ☐ CAMR

Unit ID# **GT 401**	Unit Type **CT**	Source Category **Industrial Turbine** NAICS Code **22-Utilities**		
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): **6/2010**			Check One: Actual ☐ Projected X	

Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR-CAMR Nameplate Capacity (MWe)

Company Name: **Shady Hills Power Company, LLC**	X Owner X Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

Facility (Source) Name (from Step 1) **Shady Hills Generating Station**

UNIT INFORMATION

STEP 4: **Complete one page for each unit located at the facility identified in STEP 1** (i.e., for each boiler, simple cycle combustion turbine, or combined cycle combustion turbine) Do not list duct burners. Indicate each program to which the unit is subject, and enter all other unit-specific information, including the name of each owner and operator of the unit and the generator ID number and nameplate capacity of each generator served by the unit. If the unit is subject to a program, then the facility (source) is also subject. (For units subject to the NO_X Budget Trading Program, a separate "Account Certificate of Representation" form must be submitted to meet requirements under that program.)

Applicable Program(s): X Acid Rain X CAIR NO_X Annual X CAIR SO_2 X CAIR NO_X Ozone Season ☐ CAMR

			Generator ID Number (Maximum 8 characters)	Acid Rain Nameplate Capacity (MWe)	CAIR-CAMR Nameplate Capacity (MWe)
Unit ID# **GT 501**	Unit Type **CT**	Source Category **Industrial Turbine**			
		NAICS Code **22-Utilities**			
Date unit began (or will begin) serving any generator producing electricity for sale (including test generation) (mm/dd/yyyy): **5/2010**		Check One: Actual ☐ Projected X			

Company Name: **Shady Hills Power Company, LLC**	X Owner X Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator
Company Name:	☐ Owner ☐ Operator

Facility (Source) Name (from Step 1) **Shady Hills Generating Station**

STEP 5: Read the appropriate certification statements, sign, and date.

Acid Rain Program

I certify that I was selected as the designated representative or alternate designated representative (as applicable) by an agreement binding on the owners and operators of the affected source and each affected unit at the source (i.e., the source and each unit subject to the Acid Rain Program, as indicated in "Applicable Program(s)" in Step 4).

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

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

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

> I have given a written notice of my selection as the designated representative or alternate designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the affected source and each affected unit at the source; and
>
> Allowances, and proceeds of transactions involving allowances, will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of allowances, allowances and proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source (i.e., the source and each unit subject to the CAIR NO_X Annual Trading Program, as indicated in "Applicable Program(s)" in Step 4).

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

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

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

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_X source and each CAIR NO_X unit at the source; and
>
> CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X allowances by contract, CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in accordance with the contract.

Facility (Source) Name (from Step 1) **Shady Hills Generating Station**

Clean Air Interstate Rule (CAIR) SO_2 Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source (i.e., the source and each unit subject to the SO_2 Trading Program, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program, on behalf of the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

I certify that the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO_2 unit, or where a utility or industrial customer purchases power from a CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that:

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR SO_2 source and each CAIR SO_2 unit at the source; and
>
> CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO_2 allowances by contract, CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program

I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative (as applicable), by an agreement binding on the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source (i.e., the source and each unit subject to the CAIR NO_X Ozone Season Trading Program, as indicated in "Applicable Program(s)" in Step 4).

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

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

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

> I have given a written notice of my selection as the CAIR designated representative or alternate CAIR designated representative (as applicable) and of the agreement by which I was selected to each owner and operator of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit; and
>
> CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X Ozone Season allowances by contract, CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.

Clean Air Mercury Rule (CAMR) Hg Budget Trading Program

I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each Hg Budget unit at the source (i.e., the source and each unit subject to CAMR, as indicated in "Applicable Program(s)" in Step 4).

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

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

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

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

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

Clean Air Mercury Rule (CAMR) Program Other Than the Hg Budget Trading Program

I certify that I was selected as the Hg designated representative or alternate Hg designated representative, as applicable, by an agreement binding on the owners and operators of the source and each electric generating unit (EGU) (as defined at 40 CFR 60.24(h)(8)) at the source (i.e., the source and each unit subject to CAMR, as indicated in "Applicable Program(s)" in Step 4).

I certify that I have all the necessary authority to carry out my duties and responsibilities under a State Plan approved by the Administrator as meeting the requirements of 40 CFR 60.24(h) on behalf of the owners and operators of the source and of each EGU at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.

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

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an EGU, or where a utility or industrial customer purchases power from an EGU under a life-of-the-unit, firm power contractual arrangement, I certify that I have given a written notice of my selection as the Hg designated representative or alternate Hg designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each EGU at the source.

Facility (Source) Name (from Step 1) **Shady Hills Generating Station**

General

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

Roy S. Belden Signature (Designated Representative)	Date May 7, 2008
Signature (Alternate Designated Representative)	Date

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   Two simple-cycle combustion turbines.

3. Emissions Unit Identification Number: **005 and 006**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A			**49**

8. Federal Program Applicability: (Check all that apply)

   ☒ Acid Rain Unit

   ☒ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: **GE** Model Number: **7FA**

10. Generator Nameplate Rating: **182 MW/CT**

11. Emissions Unit Comment:

    Two simple cycle General Electric Model 7FA (GE7FA) combustion turbines.

Emissions Unit Control Equipment/Method: Control 1 of 1

1. Control Equipment/Method Description: **Water injection for NO_x control (distillate oil firing).** **Dry Low NO_x burner for NO_x control (natural gas burning).**	
2. Control Device or Method Code: **028, 205**	

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,889** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **5,000** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rates: Natural gas firing - 1,704 MMBtu/CT/hr** **Distillate fuel oil firing - 1,889 MMBtu/CT/hr** **Maximum heat input rates are based on lower heating value of each fuel at ambient conditions of 59 degree F, 60 percent RH, 100 percent load, and 14.7 psi pressure.** **Fuel oil firing limited to an average of 1,000 hr/CT/yr.** **Annual operation limited to an average of 3,390 hr/CT/yr.** **No single CT is permitted to operate more than 5,000 hr/yr.**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **005 and 006**	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **75** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,113** °F	9. Actual Volumetric Flow Rate: **2,462,317 acfm**	10. Water Vapor: **8.4**%
11. Maximum Dry Standard Flow Rate: dscfm	12. Non stack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **347.0** North (km): **3,139.0**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **28/22/00** Longitude (DD/MM/SS) **82/30/00**	
15. Emission Point Comment: **Exit temperature and flow rates from PSD Report.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Natural-Gas Firing**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **1.826**	5. Maximum Annual Rate: **6,191.4**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933**
10. Segment Comment: **Based on natural gas lower heating value (LHV) of 933 Btu/ft^3.** **Maximum hourly rate = 1,704 MMBtu/hr /933 MMBtu/MM ft^3 = 1.826 MM ft^3/CT/hr** **Maximum annual rate = 1.826 MM ft^3/hr x 3,390 hr/yr = 6,191.4 MM ft^3/CT/yr**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil Firing**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **14.3**	5. Maximum Annual Rate: **14,310.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment: **Based on distillate oil LHV of 132 MMBtu/1,000 gal** **Maximum hourly rate = 1,889 MMBtu/hr /132 MMBtu/1,000 gal = 14,310.6 gal/CT/hr** **Maximum annual rate = 14,310.6 gal/hr x 1,000 hr/yr = 14,310,606 gal/CT/yr**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
PM_{10}			EL
CO			EL
VOC			EL
SO_2			EL
NO_x	028, 205		EL

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.0** lb/hour **19.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **17.0 lb/hr** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. Annual emissions = (17.0 lb/hr x 1,000 hr/yr + 9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 19.255 TPY/CT**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions based on distillate oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9.0 lb/hr**	4. Equivalent Allowable Emissions: **9.0** lb/hour **15.3** tons/year
5. Method of Compliance: **VE Test using EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/y.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **17.0 lb/hr**	4. Equivalent Allowable Emissions: **17.0** lb/hour **8.5** tons/year
5. Method of Compliance: **VE Test using EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.0** lb/hour **19.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **17.0 lb/hr** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. Annual emissions = (17.0 lb/hr x 1,000 hr/yr + 9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 19.255 TPY/CT**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions based on distillate oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9.0 lb/hr**	4. Equivalent Allowable Emissions: **9.0** lb/hour **15.3** tons/year
5. Method of Compliance: **VE Test using EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **17.0 lb/hr**	4. Equivalent Allowable Emissions: **17.0** lb/hour **8.5** tons/year
5. Method of Compliance: **VE Test using EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **66.2** lb/hour **68.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **20 ppmvd** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. Annual emissions = (66.2 lb/hr x 1,000 hr/yr + 29.7 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 68.59 TPY/CT**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions and ppm concentration based on distillate oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd**	4. Equivalent Allowable Emissions: **29.7** lb/hour **50.3**tons/year
5. Method of Compliance: **Annual testing using using EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **66.2** lb/hour **33.1** tons/year
5. Method of Compliance: **Annual testing using using EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

~~**Allowable Emissions** Allowable Emissions ____ of ____~~

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.5** lb/hour **7.34**tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **4 ppmvd** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.
Annual emissions = (7.5 lb/hr x 1,000 hr/yr + 3.0 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 7.34 TPY/CT

11. Potential, Fugitive, and Actual Emissions Comment:
Hourly emissions based on distillate oil firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.6 ppmvd**	4. Equivalent Allowable Emissions: **3.0**lb/hour **5.1** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/yr.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **4.0 ppmvd**	4. Equivalent Allowable Emissions: **7.5** lb/hour **3.75** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9.9** lb/hour **16.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015 % S** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing.
Annual emissions = (3.0 lb/hr x 1,000 hr/yr + 9.9 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 13.3 TPY/CT

11. Potential, Fugitive, and Actual Emissions Comment:

Hourly emissions based on natural gas firing. Potential annual emissions based on firing natural gas for 3,390 hr/yr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 grains/ 100 cf**	4. Equivalent Allowable Emissions: **9.9** lb/hour **16.8** tons/year
5. Method of Compliance: **Use of pipeline natural gas (sulfur content 2grains/100 ft^3).**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/y.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015 % S**	4. Equivalent Allowable Emissions: **3.0** lb/hour **1.5** tons/year
5. Method of Compliance: **Use of distillate oil with a maximum of 0.0015 percent sulfur. Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

~~**Allowable Emissions** Allowable Emissions _____ of _____~~

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **323** lb/hour **232** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **42 ppmvd at 15 percent O_2** Reference: **Vendor Data**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Annual emissions based on 1,000 hr/yr of distillate oil firing and 2,390 hr/yr of natural gas firing. Annual emissions = (323.0 lb/hr x 1,000 hr/yr + 59 lb/hr x 2,390 hr/yr) x ton/2,000 lb = 232.005 TPY/CT**	
11. Potential, Fugitive, and Actual Emissions Comment: **Hourly emissions based on distillate oil firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **9 ppmvd at 15 percent O_2.**	4. Equivalent Allowable Emissions: **59** lb/hour **100** tons/year
5. Method of Compliance: **CEM Data (24-hour block average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing for 3,390 hr/yr.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd at 15 percent O_2.**	4. Equivalent Allowable Emissions: **323** lb/hour **161.5** tons/year
5. Method of Compliance: **CEM Data (3-hour average)**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on distillate oil firing for 1,000 hr/yr.**	

~~Allowable Emissions Allowable Emissions ____ of ____~~

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE 99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **FDEP Rule 62-201.700(1),allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunctions. Allowable excess emissions are also requested for major tuning events.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Continuous monitoring of NO_x emissions. 40 CFR Part 75.**	

Continuous Monitoring System: Continuous Monitor ____ of ____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ____
2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ____
3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ____
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ____
   ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ____
   ☐ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ ~~To be Submitted, Date (if known):~~ ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ____ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☐ Attached, Document ID: ____ ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ____ ☒ Not Applicable	

Additional Requirements for Title V Air Operation Permit Applications – N/A

1. Identification of Applicable Requirements ☐ Attached, Document ID:____ ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☐ Not Applicable	
3. Alternative Methods of Operation ☐ Attached, Document ID:____ ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☐ Not Applicable	

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   Emergency generator.

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
A		**May 2010**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: **2.5 MW**

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:	
2. Control Device or Method Code:	

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1.	Maximum Process or Throughput Rate:		
2.	Maximum Production Rate:		
3.	Maximum Heat Input Rate: **21** million Btu/hr		
4.	Maximum Incineration Rate:	pounds/hr tons/day	
5.	Requested Maximum Operating Schedule:	**24** hours/day **52** weeks/year	**7** days/week **500** hours/year
6.	Operating Capacity/Schedule Comment:		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **007**	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code:	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: **2,462,317 acfm**	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **347.0** North (km): **3,139.0**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **28/22/00** Longitude (DD/MM/SS) **82/30/00**	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Diesel**		
2. Source Classification Code (SCC): **2-01-001-02**	3. SCC Units: **1000 gallons of Distillate Oil (Diesel) Burned**	
4. Maximum Hourly Rate: **155.5**	5. Maximum Annual Rate: **77,750**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Maximum hourly rate = 21.01 MMBtu/hr / 138 MMBtu/1000 gal = 155.5 gal/hr** **Maximum annual rate = 155.5 gal/hr x 500 hr/yr = 77,750 gal/hr**		

Segment Description and Rate: Segment __ of __

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

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

Segment Description and Rate: Segment _ of _

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

Segment Description and Rate: Segment _ of _

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **2.8** lb/hour **0.71** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.075 g/hp-/hr** Reference: **40 CFR 60 Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.075 g/hp-hr**	4. Equivalent Allowable Emissions: **2.8** lb/hour **0.71** tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

<u>Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions</u>

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **18.4** lb/hour **4.60** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2.6 g/hp-hr** Reference: **40 CFR 60 Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.6 g/hp-hr**	4. Equivalent Allowable Emissions: **18.4** lb/hour **4.6** tons/year
5. Method of Compliance: **500 hours per year operation, low sulfur distillate.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.1** lb/hour **1.76** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.0 g/hp-hr** Reference: **40 CFR 60 Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **1.0 g/hp-hr**	4. Equivalent Allowable Emissions: **7.1** lb/hour **1.76** tons/year
5. Method of Compliance: **500 hours per year operation, low sulfur distillate.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.03** lb/hour **0.01** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.0015% S** Reference: **Low sulfur distillate**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.0015% S**	4. Equivalent Allowable Emissions: **0.03** lb/hour **0.01** tons/year
5. Method of Compliance: **500 hours per year operation, low sulfur distillate.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.6** lb/hour **6.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **3.8 g/hp-hr** Reference: **40 CFR 60 Subpart IIII**	7. Emissions Method Code: **0**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions:	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.8 g/hp-hr**	4. Equivalent Allowable Emissions: **26.6** lb/hour **6.7** tons/year
5. Method of Compliance: **500 hours per year operation, low sulfur distillate.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10 %** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **FDEP Rule 62-201.700(1),allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunctions.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ________
2.	Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ________
3.	Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ________
4.	Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ________ ☐ Not Applicable (construction application)
5.	Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date ________ ☐ Not Applicable

6. Compliance Demonstration Reports/Records: ☐ Attached, Document ID: _________ Test Date(s)/Pollutant(s) Tested: ______________________ ☐ Previously Submitted, Date: _______ Test Date(s)/Pollutant(s) Tested: ______________________ ☐ To be Submitted, Date (if known): __________ Test Date(s)/Pollutant(s) Tested: ______________________ ☒ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute: ☐ Attached, Document ID: _________ ☒ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☐ Attached, Document ID: ________ ☒ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ________ ☒ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications – N/A

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: ________
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: ________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: ________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: ________ ☐ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

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

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

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

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Natural Gas Heater

3. Emissions Unit Identification Number: **008**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:
C		**May 2010**	**49**

8. Federal Program Applicability: (Check all that apply)

   ☐ Acid Rain Unit

   ☐ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

Emissions Unit Control Equipment/Method: Control __ of __

1. Control Equipment/Method Description:
2. Control Device or Method Code:

B. EMISSIONS UNIT CAPACITY INFORMATION
(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **10** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	 **7**days/week **3,390**hours/year
6. Operating Capacity/Schedule Comment:	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **008**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **30** feet	7. Exit Diameter: **1** feet
8. Exit Temperature: **500**°F	9. Actual Volumetric Flow Rate: **4,950** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **347.0** North (km): **3,139.0**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **28/22/00** Longitude (DD/MM/SS) **82/30/00**	
15. Emission Point Comment: **Table 2-5 of PSD Report presents emission point information.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Natural gas**		
2. Source Classification Code (SCC):	3. SCC Units: **1,000,000 SCF**	
4. Maximum Hourly Rate: **0.01**	5. Maximum Annual Rate: **83.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,055**
10. Segment Comment: **Maximum hourly rate = 10 MMBtu/hr / 1055 MMBtu/MMscf = 0.009 MMscf/hr** **Maximum annual rate = 0.009 MMscf/hr x 8,760 hr/yr = 83.03 MMscf/yr**		

Segment Description and Rate: Segment __ of __

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

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

Segment Description and Rate: Segment _ of _

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

Segment Description and Rate: Segment _ of _

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			NS
PM/PM10			NS
NOx			NS
SO2			NS
VOC			NS

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.8** lb/hour **3.49** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.08 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.08 lb/MMBtu x 10 MMBtu/hr = 0.8 lb/hr** **0.8 lb/hr x 8,760 hr/yr / (2,000 lb/ton) = 3.49 TPY/unit**	
11. Potential Fugitive and Actual Emissions Comment: **PSD Report, Table 2-5.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.08 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.8** lb/hour **3.49** tons/year
5. Method of Compliance: **Natural gas combustion.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.95** lb/hour **4.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.095 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.095 lb/MMBtu x 10 MMBtu/hr = 0.95 lb/hr** **0.95 lb/hr x 8,760 hr/yr / (2,000 lb/ton) = 4.2 TPY/unit**	
11. Potential Fugitive and Actual Emissions Comment: **PSD Report, Table 2-5.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.095 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.95** lb/hour **4.2** tons/year
5. Method of Compliance: **Natural gas combustion.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.054** lb/hour **0.237** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **2 gr / 100 SCF-gas** Reference: **Typical maximum for natural gas.**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **See PSD Report, Table 2-5.**	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 gr / 100 SCF**	4. Equivalent Allowable Emissions: **0.054** lb/hour **0.237** tons/year
5. Method of Compliance: **Natural gas combustion.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

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

Allowable Emissions Allowable Emissions _____ of _____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.02** lb/hour **0.079** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.002 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **0.002 lb/MMBtu x 10 MMBtu/hr = 0.02 lb/hr** **0.02 lb/hr x 8,760 hr/yr / (2,000 lb/ton) = 0.079 TPY/unit**	
11. Potential Fugitive and Actual Emissions Comment: **PSD Report, Table 2-5.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **0.02** lb/hour **0.079** tons/year
5. Method of Compliance: **EPA Method 9**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

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

(Optional for unregulated emissions units.)

Complete a Subsection F1 for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V operation permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.05** lb/hour **0.228** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.005 lb/MMBtu** Reference: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
0.005 lb/MMBtu x 10 MMBtu/hr = 0.05 lb/hr
0.05 lb/hr x 8,760 hr/yr / (2,000 lb/ton) = 0.228 TPY/unit

11. Potential Fugitive and Actual Emissions Comment:
PSD Report, Table 2-5.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.005 lb/MMBtu**	4. Equivalent Allowable Emissions: **0.05** lb/hour **0.228** tons/year
5. Method of Compliance: **Natural gas combustion.**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions ____ of ____

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

Allowable Emissions Allowable Emissions ____ of ____

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment: **FDEP Rule 62-201.700(1), allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown and malfunctions.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor ___ of ___

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date __________

2. Fuel Analysis or Specification: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date __________

3. Detailed Description of Control Equipment: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **See PSD Report** ☐ Previously Submitted, Date __________

4. Procedures for Startup and Shutdown: (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date __________
☒ Not Applicable (construction application)

5. Operation and Maintenance Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☐ Attached, Document ID: __________ ☐ Previously Submitted, Date __________
☒ Not Applicable

6. Compliance Demonstration Reports/Records:
☐ Attached, Document ID: __________
Test Date(s)/Pollutant(s) Tested: __________

☐ Previously Submitted, Date: ______
Test Date(s)/Pollutant(s) Tested: __________

☐ To be Submitted, Date (if known): __________
Test Date(s)/Pollutant(s) Tested: __________

☒ Not Applicable

Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute: ☐☒ Attached, Document ID: **See PSD Report**   ☐ Not Applicable

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **See PSD Report** ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications – N/A

1.	Identification of Applicable Requirements: ☐ Attached, Document ID: __________
2.	Compliance Assurance Monitoring: ☐ Attached, Document ID: __________ ☐ Not Applicable
3.	Alternative Methods of Operation: ☐ Attached, Document ID: __________ ☐ Not Applicable
4.	Alternative Modes of Operation (Emissions Trading): ☐ Attached, Document ID: __________ ☐ Not Applicable

Additional Requirements Comment

APPENDIX A

EXPECTED PERFORMANCE AND EMISSION INFORMATION ON "GE 7FA" COMBUSTION TURBINES

TABLE A-1
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 1	59 °F Case 2	95 °F Case 3
Combustion Turbine Performance			
Net power output (MW)	201.803	181.599	161.722
Net heat rate (Btu/kWh, LHV)	9,080	9,385	9,596
(Btu/kWh, HHV)	10,078	10,418	10,652
Heat Input (MMBtu/hr, LHV)	1,832.3	1,704.4	1,551.9
(MMBtu/hr, HHV)	2,033.8	1,891.9	1,722.6
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass Flow (lb/hr)- provided	3,929,264	3,650,916	3,333,093
- provided	NA	NA	NA
Temperature (°F) - provided	1,074	1,113	1,154
Moisture (% Vol.)	7.55	8.37	9.88
Oxygen (% Vol.)	12.75	12.57	12.34
Molecular Weight	28.48	28.38	28.22
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)	1,832.3	1,704.4	1,551.9
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	87,985	81,843	74,520
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,963,009	1,825,979	1,662,601
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	3,929,264	3,650,916	3,333,093
	1,074	1,113	1,154
Molecular weight	28.48	28.38	28.22
Volume flow (acfm)	2,575,419	2,462,317	2,320,037
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	168.7	161.3	152.0

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 1	59 °F Case 2	95 °F Case 3
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
Fuel use (cf/hr)	1,963,009	1,825,979	1,662,601
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT emission rate (lb/hr) - calculated	11.2	10.4	9.5
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	10.8	11.0	11.0
	9	9	9
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	63.6	59.4	53.8
CT Emission rate (lb/hr) - provided	63.0	59.0	53.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	9.0	9.0	9.0
Basis, ppmvd @ 15% O2 - calculated	7.5	7.4	7.4
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	32.1	29.7	26.8
CT Emission rate (lb/hr) - provided	32.0	29.0	26.0

TABLE A-2
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 1	 59 °F Case 2	 95 °F Case 3
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @ 15% O2 - calculated	1.3	1.3	1.3
Moisture (%)	7.55	8.37	9.88
Oxygen (%) wet	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Turbine Flow (acfm)	2,575,419	2,462,317	2,320,037
Turbine Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Turbine Exhaust Temperature (°F)	1,074	1,113	1,154
CT emission rate (lb/hr) - calculated	3.26	3.02	2.72
CT Emission rate (lb/hr) - provided	3.00	2.80	2.60
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	11.2	10.4	9.5
	10	10	10
Stack emission rate (lb/hr)- calculated	1.72	1.60	1.45
- provided	NA	NA	NA
Lead			
Emission Rate Basis	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-3
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 75% LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 4	 59 °F Case 5	 95 °F Case 6
Combustion Turbine Performance			
Net power output (MW)	151.348	138.128	121.310
Net heat rate (Btu/kWh, LHV)	9,942	10,067	10,589
(Btu/kWh, HHV)	11,036	11,175	11,753
Heat Input (MMBtu/hr, LHV)	1,504.7	1,390.6	1,284.5
(MMBtu/hr, HHV)	1,670.2	1,543.5	1,425.8
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass flow (lb/hr)- provided	2,956,564	2,941,381	2,762,226
- provided	NA	NA	NA
Temperature (°F) - provided	1,200	1,159	1,190
Moisture (% Vol.)	8.13	8.26	9.80
Oxygen (% Vol.)	12.11	12.60	12.43
Molecular Weight	28.44	28.41	28.22
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)	1,505	1,391	1,285
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	72,254	66,774	61,681
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,612,040	1,489,784	1,376,156
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,956,564	2,941,381	2,762,226
	1,200	1,159	1,190
Molecular weight	28.44	28.41	28.22
Volume flow (acfm)	2,100,040	2,040,226	1,965,203
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	137.5	133.6	128.7

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 75% LOAD

Parameter	**Turbine Inlet Temperature** 20 °F Case 4	59 °F Case 5	95 °F Case 6
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
Fuel use (cf/hr)	1,612,040	1,489,784	1,376,156
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT Stack emission rate (lb/hr)- calculated	9.2	8.5	7.9
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	11.8	10.9	10.9
	9	9	9
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	51.7	47.8	44.1
CT Emission rate (lb/hr) - provided	51.0	47.0	44.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	9.0	9.0	9.0
Basis, ppmvd @ 15% O2 - calculated	6.9	7.4	7.5
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	24.1	23.9	22.2
CT Emission rate (lb/hr) - provided	24.0	24.0	22.0

TABLE A-4
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 75% LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 4	59 °F Case 5	95 °F Case 6
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @15% O2 - calculated	1.2	1.3	1.3
Moisture (%)	8.13	8.26	9.8
Oxygen (%)	12.11	12.60	12.43
Oxygen (%) dry	13.18	13.73	13.78
Turbine Flow (acfm)	2,100,040	2,040,226	1,965,203
Turbine Flow (acfm, dry)	1,929,307	1,871,704	1,772,613
Turbine Exhaust Temperature (°F)	1,200	1,159	1,190
CT Emission rate (lb/hr) - calculated	2.44	2.43	2.26
CT Emission rate (lb/hr) - provided	2.40	2.20	2.20
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	9.2	8.5	7.9
	10	10	10
Stack emission rate (lb/hr)- calculated	1.41	1.30	1.20
- provided	NA	NA	NA
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-5
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 50% LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 7	59 °F Case 8	95 °F Case 9
Combustion Turbine Performance			
Net power output (MW)	100.897	92.126	80.909
Net heat rate (Btu/kWh, LHV)	11,762	12,083	12,654
(Btu/kWh, HHV)	13,056	13,412	14,046
Heat Input (MMBtu/hr, LHV)	1,186.7	1,113.1	1,023.8
(MMBtu/hr, HHV)	1,317.3	1,235.6	1,136.5
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	20,825	20,825	20,825
(Btu/lb, HHV)	23,116	23,116	23,116
(HHV/LHV)	1.110	1.110	1.110
CT Exhaust Flow			
Mass flow (lb/hr)- provided	2,498,048	2,433,269	2,325,978
- provided	NA	NA	NA
Temperature (°F) - provided	1,200	1,200	1,200
Moisture (% Vol.)	7.54	7.96	9.37
Oxygen (% Vol.)	12.77	12.94	12.92
Molecular Weight	28.48	28.42	28.25
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)	1,187	1,113	1,024
Heat content (Btu/lb, LHV)	20,825	20,825	20,825
Fuel usage (lb/hr)- calculated	56,986	53,452	49,164
Heat content (Btu/cf, LHV)- assumed	933	933	933
	0.0448	0.0448	0.0448
Fuel usage (cf/hr)- calculated	1,271,405	1,192,548	1,096,884
Stack			
Stack Height (ft)	75	75	75
Stack Diameter (ft)	18	18	18
Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,498,048	2,433,269	2,325,978
	1,200	1,200	1,200
Molecular weight	28.48	28.42	28.25
Volume flow (acfm)	1,771,785	1,729,434	1,663,345
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	116.0	113.3	108.9

Source: GE, 2007- CT Performance Data; Golder, 2008

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 50% LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 7	59 °F Case 8	95 °F Case 9
Particulate Matter (Front-half only)			
Particulate from CT- provided	9.0	9.0	9.0
Sulfur Dioxide			
Fuel use (cf/hr)	1,271,405	1,192,548	1,096,884
Sulfur content (grains/ 100 cf)	2	2	2
	2	2	2
CT Stack emission rate (lb/hr)- calculated	7.3	6.8	6.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	10.8	10.4	10.1
	9	9	9
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	40.3	37.8	34.8
CT Emission rate (lb/hr) - provided	40.0	37.0	34.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	9.0	9.0	9.0
Basis, ppmvd @15% O2 - calculated	7.5	7.8	8.0
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	20.4	19.9	18.8
CT Emission rate (lb/hr) - provided	20.0	20.0	19.0

TABLE A-6
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, NATURAL GAS, 50% LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 7	59 °F Case 8	95 °F Case 9
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	1.6	1.6	1.6
Basis, ppmvd @15% O2 - calculated	1.3	1.4	1.4
Moisture (%)	7.54	7.96	9.37
Oxygen (%)	12.77	12.94	12.92
Oxygen (%) dry	13.81	14.06	14.26
Turbine Flow (acfm)	1,771,785	1,729,434	1,663,345
Turbine Flow (acfm, dry)	1,638,192	1,591,771	1,507,489
Turbine Exhaust Temperature (°F)	1,200	1,200	1,200
CT Emission rate (lb/hr) - calculated	2.08	2.02	1.91
CT Emission rate (lb/hr) - provided	2.00	1.80	1.80
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr) = SAM Formed in the CT			
	7.3	6.8	6.3
	10	10	10
Stack emission rate (lb/hr)- calculated	1.11	1.04	0.96
- provided	NA	NA	NA
Lead			
Lead (lb/hr) = NA			
Emission Rate Basis	NA	NA	NA
HRSG Stack emission rate (lb/hr)	NA	NA	NA

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-7
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 10	59 °F Case 11	95 °F Case 12
Combustion Turbine Performance			
Net power output (MW)	199.791	187.397	164.066
Net heat rate (Btu/kWh, LHV)	10,050	10,080	10,380
(Btu/kWh, HHV)	10,653	10,685	11,003
Heat Input (MMBtu/hr, LHV)	2,007.9	1,888.96	1,703.0
(MMBtu/hr, HHV)	2,128.4	2,002.3	1,805.2
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- provided	4,055,000	3,766,000	3,407,000
Temperature (°F) - provided	1,053	1,093	1,143
Moisture (% Vol.)	10.87	11.46	13.07
Oxygen (% Vol.)	11.24	11.11	10.77
Molecular Weight	28.36	28.30	28.12
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)	2,007.9	1,889.0	1,703.0
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	109,721	103,222	93,061
Stack			
Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
HRSG Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)^2 /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr) - provided	4,055,000	3,766,000	3,407,000
	1,053	1,093	1,143
Molecular weight	28.36	28.30	28.12
CT volume flow (acfm)	2,632,958	2,515,327	2,363,790
	43,883	41,922	39,397
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	172.4	164.7	154.8

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 10	59 °F Case 11	95 °F Case 12
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil use (lb/hr)	109,721	103,222	93,061
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	3.3	3.1	2.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	59.0	59.5	60.6
	42	42	42
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	345.9	322.3	293.5
CT Emission rate (lb/hr) - provided	345.0	323.0	293.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	20.0	20.0	20.0
Basis, ppmvd @15% O2 - calculated	14.2	14.1	13.9
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,337,014	2,235,874	2,109,210
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	71.1	66.2	60.5
CT Emission rate (lb/hr) - provided	71.0	66.0	59.0

TABLE A-8
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DISTILLATE OIL, BASE LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 10	59 °F Case 11	95 °F Case 12
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @15% O2 - calculated	2.8	2.8	2.8
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Turbine Flow (acfm)	2,632,958	2,515,327	2,363,790
Turbine Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Turbine Exhaust Temperature (°F)	1,053	1,093	1,143
CT emission rate (lb/hr) - calculated	8.2	7.5	6.7
CT Emission rate (lb/hr) - provided	8.0	7.5	7.0
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	3.3	3.1	2.8
	10	10	10
Stack emission rate (lb/hr)- calculated	0.50	0.47	0.43
- provided	NA	NA	NA
Lead			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0281	0.0264	0.0238

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-9
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DISTILLATE OIL, 75% LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 13	 59 °F Case 14	 95 °F Case 15
Combustion Turbine Performance			
Net power output (MW)	149.812	139.907	123.076
Net heat rate (Btu/kWh, LHV)	10,970	11,030	11,400
(Btu/kWh, HHV)	11,628	11,692	12,084
Heat Input (MMBtu/hr, LHV)	1,643.4	1,543.2	1,403.1
(MMBtu/hr, HHV)	1,742.0	1,635.8	1,487.3
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,991,000	2,898,000	2,783,000
- provided	NA	NA	NA
Temperature (°F) - provided	1,196	1,200	1,200
Moisture (% Vol.)	11.72	11.85	12.65
Oxygen (% Vol.)	10.34	10.57	10.86
Molecular Weight	28.32	28.29	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)	1,643.4	1,543.2	1,403.1
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	89,805	84,326	76,670
HRSG Stack			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,991,000	2,898,000	2,783,000
	1,196	1,200	1,200
Molecular weight	28.32	28.29	28.16
CT volume flow (acfm)	2,128,442	2,069,745	1,996,279
	35,474	34,496	33,271
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	139.4	135.6	130.7

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE 7FA, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature		
	20 °F Case 13	59 °F Case 14	95 °F Case 15
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	89,805	84,326	76,670
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.7	2.5	2.3
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	65.4	63.4	60.3
	42	42	42
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	280.4	263.3	239.2
CT Emission rate (lb/hr) - provided	280.0	263.0	239.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	20.0	20.0	20.0
Basis, ppmvd @15% O2 - calculated	12.8	13.2	13.9
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	52.2	50.6	48.3
CT Emission rate (lb/hr) - provided	52.0	51.0	48.0

TABLE A-10
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE 7FA, DISTILLATE OIL, 75% LOAD

Parameter	Turbine Inlet Temperature		
	20 °F Case 13	59 °F Case 14	95 °F Case 15
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @15% O2 - calculated	2.6	2.6	2.8
Moisture (%)	11.72	11.85	12.65
Oxygen (%)	10.34	10.57	10.86
Oxygen (%) dry	11.71	11.99	12.43
Turbine Flow (acfm)	2,127,478	2,068,807	1,995,375
Turbine Flow (acfm, dry)	1,878,138	1,823,654	1,742,960
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	6.0	5.8	5.5
CT Emission rate (lb/hr) - provided	6.0	5.5	5.5
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	2.7	2.5	2.3
	10	10	10
Stack emission rate (lb/hr)- calculated	0.41	0.39	0.35
- provided	NA	NA	NA
Lead			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0230	0.0216	0.0196

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-11
DESIGN INFORMATION AND STACK PARAMETERS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DISTILLATE OIL, 50% LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 16	59 °F Case 17	95 °F Case 18
Combustion Turbine Performance			
Net power output (MW)	99.844	93.237	81.983
Net heat rate (Btu/kWh, LHV)	12,730	12,920	13,370
(Btu/kWh, HHV)	13,494	13,695	14,172
Heat Input (MMBtu/hr, LHV)	1,271.0	1,204.6	1,096.1
(MMBtu/hr, HHV)	1,347.3	1,276.9	1,161.9
Relative Humidity (%)	80	60	64
Fuel heating value (Btu/lb, LHV)	18,300	18,300	18,300
(Btu/lb, HHV)	19,398	19,398	19,398
(HHV/LHV)	1.060	1.060	1.060
CT Exhaust Flow			
Mass Flow (lb/hr)- with no margin	2,499,000	2,457,000	2,353,000
- provided	NA	NA	NA
Temperature (°F) - provided	1,196	1,200	1,200
Moisture (% Vol.)	10.19	10.38	11.37
Oxygen (% Vol.)	11.30	11.54	11.73
Molecular Weight	28.44	28.40	28.26
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)	1,271.0	1,204.6	1,096.1
Heat content (Btu/lb, LHV)	18,300	18,300	18,300
Fuel usage (lb/hr)- calculated	69,454	65,826	59,897
HRSG Stack			
HRSG - Stack Height (ft)	75	75	75
Diameter (ft)	18	18	18
Stack Flow Conditions			
Velocity (ft/sec) = Volume flow (acfm) / [((diameter)² /4) x 3.14159] / 60 sec/min			
Mass flow (lb/hr)	2,499,000	2,457,000	2,353,000
	1,196	1,200	1,200
Molecular weight	28.44	28.40	28.26
CT volume flow (acfm)	1,770,922	1,748,009	1,682,253
	29,515	29,133	28,038
Diameter (ft)	18	18	18
Velocity (ft/sec)- calculated	116.0	114.5	110.2

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE 7FA, DISTILLATE OIL, 50% LOAD

Parameter	**Turbine Inlet Temperature**		
	20 °F	**59 °F**	**95 °F**
	Case 16	**Case 17**	**Case 18**
Particulate Matter (Front-half only)			
Particulate from CT- provided	17.0	17.0	17.0
Sulfur Dioxide			
Fuel oil Sulfur Content	0.0015%	0.0015%	0.0015%
Fuel oil use (lb/hr)	69,454	65,826	59,897
lb SO2 / lb S (64/32)	2	2	2
Stack emission rate (lb/hr)- calculated	2.1	2.0	1.8
Nitrogen Oxides			
NOx (lb/hr) = NOx (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - calculated	59.2	57.1	54.6
	42	42	42
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	214.9	203.6	185.2
CT Emission rate (lb/hr) - provided	215.0	203.0	185.0
Carbon Monoxide			
CO (lb/hr) = CO (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	20.0	20.0	20.0
Basis, ppmvd @15% O2 - calculated	14.2	14.7	15.4
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	44.2	43.4	41.3
CT Emission rate (lb/hr) - provided	44.0	43.0	41.0

TABLE A-12
MAXIMUM EMISSIONS FOR CRITERIA POLLUTANTS FOR THE SHADY HILLS GENERATING STATION PROJECT
GE 7FA, DISTILLATE OIL, 50% LOAD

Parameter	Turbine Inlet Temperature 20 °F Case 16	59 °F Case 17	95 °F Case 18
Volatile Organic Compounds			
VOC (lb/hr) = VOC (ppm actual) x Volume flow (acfm) x			
Basis, ppmvd - provided	4.0	4.0	4.0
Basis, ppmvd @15% O2 - calculated	2.8	2.9	3.1
Moisture (%)	10.19	10.38	11.37
Oxygen (%)	11.30	11.54	11.73
Oxygen (%) dry	12.58	12.88	13.23
Turbine Flow (acfm)	1,770,120	1,747,217	1,681,491
Turbine Flow (acfm, dry)	1,589,745	1,565,856	1,490,306
Turbine Exhaust Temperature (°F)	1,196	1,200	1,200
CT emission rate (lb/hr) - calculated	5.0	5.0	4.7
CT Emission rate (lb/hr) - provided	5.0	5.0	4.5
Sulfuric Acid Mist			
Total Sulfuric Acid Mist (SAM) (lb/hr)= SAM Formed in the CT			
	2.1	2.0	1.8
	10	10	10
Stack emission rate (lb/hr)- calculated	0.32	0.30	0.28
- provided	NA	NA	NA
Lead			
	14	14	14
Stack emission rate (lb/hr)- calculated	0.0178	0.0169	0.0153

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-13
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
WHEN FIRING NATURAL GAS, GE7FA CT

Parameter		Emission Rate (lb/hr) firing Natural Gas for Operating Conditions of Base Load (1)	Natural Gas Maximum Annual Emissions (TPY) (2)	
		59 °F	59 °F	59 °F
			1	2
HIR (MMBtu/hr):		1,892	CT	CTs
Sulfuric acid mist		1.60	2.7	5.4
HAPs (Section 112(b) of Clean Air Act)				
1,3-Butadiene		0.000814	0.001	0.003
Acetaldehyde		0.0757	0.128	0.257
Acrolein		0.0121	0.021	0.041
Benzene		0.0227	0.038	0.077
Ethylbenzene		0.0605	0.103	0.205
Formadehyde		0.392	0.664	1.328
Naphthalene		0.00246	0.004	0.008
Polycyclic Aromatic Hydrocarbons (PAH)	(3)	0.00416	0.007	0.014
Propylene Oxide		0.0549	0.093	0.186
Toluene		0.0624	0.106	0.212
Xylene		0.121	0.205	0.410
Antimony		0.0	0.0	0.00
Arsenic		0.0	0.0	0.00
Beryllium		0.0	0.0	0.00
Cadmium		0.0	0.0	0.00
Chromium		0.0	0.0	0.00
Lead		0.0	0.0	0.00
Manganese		0.0	0.0	0.00
Mercury		1.89E-06	0.0	6.41E-06
Nickel		0.0	0.0	0.00
Selenium		0.0	0.0	0.00
HAPs (Total)		0.808	1.4	2.7

(1) Emissions based on the following emission factors and conversion factors for firing natural gas:

Emission Factors		Value	Reference
Sulfuric acid mist		10	
1,3-Butadiene	(a)	0.43	
Acetaldehyde		40	
Acrolein		6.4	
Benzene		12	
Ethylbenzene		32	
Formadehyde		0.091	ppmvd @15% O2 (see Table 9a)
Naphthalene		1.3	
Polycyclic Aromatic Hydrocarbons (PAH)		2.2	
Propylene Oxide	(a)	29	
Toluene		33	
Xylene		64	
Antimony		0.00E+00	
Arsenic		0.00E+00	
Beryllium		0.00E+00	
Cadmium		0.00E+00	
Chromium		0.00E+00	
Lead		0.00E+00	
Manganese		0.00E+00	
Mercury		1.00E-03	
Nickel		0.00E+00	
Selenium		0.00E+00	

(a) Based on 1/2 the detection limit; expected emissions are lower.

3390 CT
0 CT/DB

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.

TABLE A-13a
MAXIMUM FORMALDEHYDE EMISSIONS
FOR THE SHADY HILLS GENERATING STATION PROJECT
GE7FA, DRY LOW NOx COMBUSTOR, NATURAL GAS, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 1	 59 °F Case 2	 95 °F Case 3
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NOx) x 2116.8 lb/ft2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr			
CH_2O (ppm actual) = CH_2O (ppmd @ 15%O_2) x [(20.9 - O_2 dry)/(20.9 - 15)]			
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/(1-Moisture (%))			
Basis, ppmvd - calculated	0.110	0.111	0.111
	0.091	0.091	0.091
Moisture (%)	7.55	8.37	9.88
Oxygen (%)	12.75	12.57	12.34
Oxygen (%) dry	13.79	13.72	13.69
Exhaust Flow (acfm)	2,575,419	2,462,317	2,320,037
Exhaust Flow (acfm, dry)	2,380,975	2,256,221	2,090,818
Exhaust Temperature (°F)	1,074	1,113	1,154
CT Emission rate (lb/hr)	0.420	0.392	0.355
	206.3	207.0	206.1

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

Source: GE, 2007- CT Performance Data; Goler, 2008

TABLE A-14
REGULATED AND HAZARDOUS AIR POLLUTANT EMISSION FACTORS AND EMISSIONS
WHEN FIRING DISTILLATE FUEL OIL, GE 7FA CTS

Parameter	Emission Rate (lb/hr) Firing Distillate Fuel Oil (1) Base Load	Maximum Annual Emissions (TPY) Distillate Fuel Oil (2)		Natural Gas (4)	Natural Gas and Fuel Oil (5)
	59 °F				
		1	2	2	2
HR (MMBtu/hr):	2,002	CT	CTs	CTs	CTs
Sulfuric acid mist	0.47	0.24	0.5	5.4	5.3
HAPs (Section 112(b) of Clean Air Act)					
1,3-Butadiene	0.0320	0.0160	0.0320	0.0028	0.034
Acetaldehyde	0.00	0.00	0.00	0.26	0.2
Acrolein	0.00	0.00	0.00	0.041	0.04
Benzene	0.110	0.0551	0.1101	0.077	0.18
Ethylbenzene	0.00	0.00	0.00	0.205	0.18
Formadehyde	0.455	0.228	0.4554	1.33	1.6
Naphthalene	0.0701	0.0350	0.0701	0.0083	0.077
Polycyclic Aromatic Hy (3)	0.0801	0.0400	0.0801	0.0141	0.09
Propylene Oxide	0.00	0.00	0.00	0.186	0.16
Toluene	0.00	0.00	0.00	0.21	0.2
Xlene	0.00	0.00	0.00	0.41	0.4
Antimony	0.00	0.00	0.00	0.00	0.0
Arsenic	0.0220	0.01101	0.02203	0.00	0.022
Beryllium	0.000621	0.000310	0.000621	0.00	0.00062
Cadmium	0.00961	0.00481	0.00961	0.00	0.0096
Chromium	0.0220	0.01101	0.02203	0.00	0.022
Lead	0.0280	0.01402	0.02803	0.00	0.028
Manganese	1.58	0.791	1.582	0.00	1.6
Mercury	0.00240	0.001201	0.002403	0.00	0.0024
Nickel	0.00921	0.00461	0.00921	0.00	0.0092
Selenium	0.0501	0.0250	0.0501	0.00	0.050
HAPs (Total)	2.47	1.24	2.47	2.7	4.9

(1) Emissions based on the following emission factors and conversion factors for firing distillate fuel oil:

Emission Factors		Value	Reference
Sulfuric acid mist		5	
1,3-Butadiene	(a)	16	
Acetaldehyde		0.0	
Acrolein		0.0	
Benzene		55	
Ethylbenzene		0.0	
Formadehyde		0.091	ppmvd 15% O2 (see Table 10a)
Naphthalene		35	
Polycyclic Aromatic Hydrocarbons (		40	
Propylene Oxide		0.0	
Toluene		0.0	
Xlene		0.0	
Antimony		0.0	
Arsenic	(a)	11	
Beryllium	(a)	0.31	
Cadmium		4.8	
Chromium		11	
Lead		14	
Manganese		790	
Mercury		1.2	
Nickel	(a)	4.6	
Selenium	(a)	25	

(a) Based on 1/2 the detection limit; expected emissions are lower.

1,000 hours

(3) Assumed to be representative of Polycyclic Organic Matter (POM) emissions, a regulated HAP.
(4) Annual emissions based on maximum emissions presented for natural gas-firing
(5) Maximum total annu 1,000 hours of firing fuel and remaining hours firing natural gas.

TABLE A-14a
MAXIMUM FORMALDEHYDE EMISSIONS
FOR THE SHADY HILLS GENERATING STATION PROJECT
GE 7FA CT, DRY LOW NOx COMBUSTOR, DISTILLATE OIL, BASE LOAD

Parameter	CT Only Turbine Inlet Temperature 20 °F Case 10	 59 °F Case 11	 95 °F Case 12
Formaldehyde (CH_2O) MW = 30			
CH_2O (lb/hr) = CH_2O (ppm actual) x Volume flow (acfm) x 46 (mole. wgt NOx) x 2116.8 lb/ft2 (pressure) / [1545.7 (gas constant, R) x Actual Temp. (°R)] x 60 min/hr			
CH_2O (ppm actual) = CH_2O (ppmd @ 15% O_2) x [(20.9 - O_2 dry)/(20.9 - 15)]			
Oxygen (%, dry)(O_2 dry) = Oxygen (%)/(1-Moisure (%))			
Basis, ppmvd - calculated	0.128	0.129	0.131
	0.091	0.091	0.091
Moisture (%)	10.87	11.46	13.07
Oxygen (%)	11.24	11.11	10.77
Oxygen (%) dry	12.61	12.55	12.39
Exhaust Flow (acfm)	2,632,958	2,515,327	2,363,790
Exhaust Flow (acfm, dry)	2,346,756	2,227,070	2,054,843
Exhaust Temperature (°F)	1,053	1,093	1,143
CT Emission rate (lb/hr)	0.489	0.455	0.415
	229.7	227.4	229.8

Note: ppmvd= parts per million, volume dry; O2= oxygen.

Source: GE, 2007- CT Performance Data; Goler, 2008

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

APPENDIX B

BEST AVAILABLE CONTROL TECHNOLOGY FOR THE PROPOSED COMBUSTION TURBINES

B.1 NEW SOURCE PERFORMANCE STANDARDS

BACT is a case-by-case emission limitation for each applicable pollutant, based on the maximum degree of emission reduction after taking into account the energy, environmental, and economic impacts, and other costs. The BACT cannot be any less stringent than any applicable new source performance standards (NSPS) and consideration must be given to the applicable NSPS in the determination of BACT. This requirement also applies for any applicable National Emission Standard for Hazardous Air Pollutants promulgated under 40 CFR Part 61.

The NSPS in Subpart KKKK limits NO_x and SO_2 emissions from all stationary CTs with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the higher heating value of the fuel fired, which commenced construction, modification, or reconstruction after February 18, 2005. CTs regulated under Subpart KKKK are exempt from the requirements of Subpart GG of this part.

Subpart KKKK requirements that would apply to the Shady Hill Generating Station are applicable to combustion turbines with heat input at peak load (HHV) 850 MMBtu/hr. The NO_x emissions are limited to 0.43 lb/MW-hr for gas-firing and 1.3 lb/MW-hr for fuel oil firing. These emission rates are approximately equivalent to 15 ppm corrected to 15-percent O_2 when firing natural gas and 42 ppm corrected to 15-percent O_2 when firing fuel oil.

For SO_2 emissions, Subpart KKKK requirements limit any gases which contain SO_2 in excess of 110 nano-grams per Joule (ng/J) (0.90 lb/MW-hr) gross output or any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. When turbines simultaneously fire multiple fuels, each fuel must meet this requirement.

In addition to emission limitations, there are requirements for notifying, record keeping, reporting, performance testing, and monitoring. These are summarized below:

<u>40 CFR 60.7 Notification and Record Keeping</u>

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

2. Notification of actual date of initial start-up - within 15 days after such date.

3. Notification of date which demonstrates CEM – postmarked not less than 30 days prior to date.

4. Maintain records of the occurrence and duration of any start-ups, shutdowns, and malfunctions.

5. Excess emissions reports – semi-annually by the 30th day following the end of each six-month period. (Required even if no excess emissions occur).

6. Maintain file of all measurements for 2 years.

B.2 BEST AVAILABLE CONTROL TECHNOLOGY

The "top-down" analysis for determining BACT, as provided for in EPA's Draft 1990 New Source Review Workshop Manual was considered in evaluating BACT for the Project. The procedure involves five steps: identification of control technologies, elimination of technically infeasible control technologies, a ranking of the control technologies, an evaluation of the effective control technologies, and the selection of BACT.

The identification of control technologies is developed from the information obtained from BACT/lowest achievable emission rate (LAER) Information System (BLIS) database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina. While these data are comprehensive it is often not up to date with the most recent BACT/LAER decisions and separate contact with state agencies is required. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51, Appendix S.II, A.18).

The elimination of infeasible technologies is based on those engineering aspects that would preclude a technology's use due to physical, chemical or other engineering consideration. Control technologies that are technically feasible are ranked by control effectiveness, with determination of the environmental, economic and energy costs; and benefits of the control technologies. This information forms the basis for the case-by-case consideration of environmental, energy, and economic impacts. The "top" feasible control alternative is selected unless it can be rejected based on economic, environmental, or energy considerations. This section of Appendix B presents information related to the proposed BACT emission limitation.

B.2.1 NITROGEN OXIDES

Identification of NO_x Control Technologies

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table B-2 presents a listing of the BACT/LAER decisions made by state environmental agencies and EPA regional offices for gas turbines including duct firing. This table was developed from the information obtained from the BLIS database maintained at EPA's National Computer Center located at Research Triangle Park, North Carolina.

Historically, the most stringent NO_x controls for CTs established as BACT/LAER by state agencies were combustion controls with selective catalytic reduction (SCR) for combined cycle operation and combustion controls alone for simple cycle operation. SCR is a post-combustion control, while advanced dry low-NO_x (DLN) combustors minimize the formation of NO_x in the combustion process.

Wet injection was the first combustion technology introduced for CTs (pre-1980s) and was the primary method of reducing NO_x emissions from CTs prior to the 1990s. Indeed, this method of control was first mandated by the NSPS to reduce NO_x levels to 75 ppmvd (corrected to 15-percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd (corrected to 15-percent O_2) when burning natural gas. Wet injection is still the only means of reducing NO_x formation in the combustion process when firing oil.

The DLN combustion technology has been developed and made available since the early 1990s for gas turbines to achieve emission levels of 25 ppmvd corrected to 15-percent O_2. More recently, however, CT manufacturers have developed DLN combustors that can reduce NO_x concentrations to 9 ppmvd (corrected to 15-percent O_2) when firing natural gas. The proposed GE7FA CTs will use DLN to achieve 9 ppmvd (corrected to 15-percent O_2) when firing natural gas.

SCR is an available and demonstrated control technology for NO_x control on combined cycle units, which has been installed or permitted in over 100 projects. However, currently there are no known installations of "Hot SCR" on GE 7FA simple cycle CTs. Furthermore, with no known installations on GE7FA simple cycle turbines, long term effects on output degradation is uncertain and a concern.

Other available control technologies that have become available for controlling NO_x emissions from CTs include SCONO$_x$™ and XONON™. SCONO$_x$™ is an add-on control using absorption and chemical conversion to remove NO_x formed from combustion, while XONON™ is a catalytic combustion system integral to the turbine. Other potential technologies used in combustion process for NO_x removal include: NO$_x$OUT, Thermal DeNO$_x$, and NSCR.

Technology Descriptions and Feasibility

Wet Injection

The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion results (i.e., CO and VOC emissions). In "F" Class turbines using wet injection with gas firing, the NO_x emission rates in the range of 30 ppm have been demonstrated. However, wet injection is no longer offered for gas firing in "F" Class turbines. Wet injection is the only current feasible means of reducing NO_x emissions in the combustion process when firing oil.

DLN Combustor

In the past several years, CT manufacturers have offered and installed machines with DLN combustors. These combustors, which are offered on conventional machines manufactured by General Electric (GE), Siemens Westinghouse, Mitsubishi Heavy Industries (MHI), and ABB, can achieve NO_x concentrations of 35 ppmvd or less when firing natural gas. All these vendors have offered DLN combustors on advanced heavy-duty industrial turbines. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of DLN combustor technology when firing natural gas. The NO_x emission level when firing natural gas at baseload conditions is 9 ppmvd (corrected to 15-percent O_2) for GE-7FA, a level which is guaranteed by GE.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural gas-fired installations either of cogeneration or combined cycle configuration. Exhaust gas temperatures of simple cycle CTs generally are in the range of 1,000°F, which exceeds the optimum range for SCR with base metal catalysts. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been primarily limited to combined-cycle facilities that burn natural gas with small amounts of fuel oil. Initially, the traditional metal catalysts used in SCR systems were contaminated by sulfur-containing fuels. For most fuel oil-burning facilities, catalyst operation was discontinued or the exhaust bypasses the SCR system. This was due to the formation of ammonium salts (ammonium sulfate and bisulfate) resulting from the reaction of NH_3 and sulfur combustion products. Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required with concomitant cost and technical requirements. Ammonium sulfate is also emitted as particulate matter. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts. Ceramic and specially designed catalysts have been designed to overcome the problems with base-metal catalysts. The sulfur in No. 2 distillate oil has also been reduced from 0.5 percent available in the early 1990s to 0.05 percent. Beginning in 2007, the sulfur content for transportation diesel fuel has been mandated by EPA to be reduced to 0.0005 percent. This ultra low-sulfur light oil will be available. In addition, HRSG designs can accommodate the impacts of the formation of ammonium salts.

For simple cycle units, SCR is technically feasible. However, currently there are no known installations of "Hot SCR" on GE 7FA simple cycle CTs. Furthermore, with no known installations on GE7FA simple cycle turbines, long term effects on output degradation is uncertain and a concern.

$SCONO_x$™ Process

$SCONO_x$™ is a NO_x and CO control system exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc. In 1998, ABB acquired the exclusive license for the technology in the United States for control applications larger than 100 MW.

The $SCONO_x$™ system employs a single catalyst to simultaneously oxidize CO to CO_2 and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The $SCONO_x$™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (3)$$

CO_2 produced by reaction (1) and (2) is released to the atmosphere as part of the CT/HRSG exhaust gas stream.

As shown in Reaction (3), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\ H_2 + CO_2 \rightarrow K_2CO_3 + 4\ H_2O_{(g)}) + N_2 \qquad (4)$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the SCONO$_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with O_2 present in ambient air. The SCONO$_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and carbon dioxide. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture is then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + \tfrac{1}{2}\ O_2 + 1.88\ N_2 \rightarrow CO + 2\ H_2 + 1.88\ N_2 \qquad (5)$$

$$CO + 2\,H_2 + H_2O + 1.88\,NO_2 \rightarrow CO_2 + 3\,H_2 + 1.88\,N_2 \quad (6)$$

The $SCONO_x$™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For $SCONO_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the $SCONO_x$™ catalyst that reforms the natural gas.

The $SCONO_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system ($SCOSO_x$™) to remove sulfur compounds is installed upstream of the $SCONO_x$™ catalyst. During regeneration of the $SCONO_x$™ catalyst, either hydrogen sulfide or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the $SCOSO_x$™ process is proprietary. $SCOSO_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \tfrac{1}{2}\,O_2 \rightarrow CO_2 \quad (7)$$

$$SO_2 + \tfrac{1}{2}\,O_2 \rightarrow SO_3 \quad (8)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \quad (9)$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O \quad (10)$$

Utility materials needed for the operation of the $SCONO_x$™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the $SCONO_x$™ control system is limited to one small combined cycle power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, utilizes a GE LM2500 turbine (30-MW size) equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The $SCONO_x$™ control system was installed at the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 ppmvd resulting in an approximate 85-percent NO_x removal efficiency.

A second $SCONO_x$™ system was installed at the Genetics Institute Facility in Andover, Massachusetts, in late 1998. The system is installed on a 5-MW Caterpillar Solar Turbine with a

Deltak boiler. The NO_x emission limit is 2.5 ppmvd at 15-percent O_2. ABB Environmental reports that the system is operating successfully, although there have been incidents of high NO_x emissions that ABB Environmental attributes to combustion control problems and not to the SCONO$_x$™ system.

XONON™ Catalytic Combustor

Catalytic combustors are being developed for low emission applications on turbines where the catalyst is internal to the combustion system. The XONON™ Combustion System is a catalytic combustion system developed by Catalytica Combustion Systems, Inc., that can achieve low emission levels of NO_x, CO, and VOCs. The XONON™ system combusts the fuel over a catalyst, reducing the temperature of combustion and providing for more complete combustion of the fuel. The system is referred to as "flameless combustion" where temperatures are below those where limited NO_x formation occurs. However, the exhaust temperatures, from a CT standpoint, are still sufficient for the expansion of the gases through the turbine for power generation. Emission levels of NO_x at less than 2 ppm have been reported for the 1.5-MW Kawasaki gas turbine located at Sun Valley Power. XONON™ is currently only being commercialized for turbines in the 1- to 15-MW range.

NO$_x$OUT Process

The NO$_x$OUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO$_x$OUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + \frac{1}{2} O_2 \rightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°F and 1,950°F. Advantages of the system are as follows:

1. Low capital and operating costs as a result of use of urea injection; and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold-end equipment downstream.

Commercial application of the NO_xOUT system is limited and the NO_xOUT system has not been demonstrated on any CT unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the GE 7FA CT is about 1,100°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal DeNO$_x$

Thermal DeNO$_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high-temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal DeNO$_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream before ammonia injection.

The only known commercial applications of Thermal DeNO$_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of material requirements, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal DeNO$_x$ process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The maximum exhaust gas temperature of an

GE 7FA CT is typically 1,100°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction

Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low-oxygen content in the exhaust gas stream and high temperature (700 to 1,400°F) in order to be effective. CTs have the required temperature but also have high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

Technology Demonstration and Feasibility

The combustion controls using DLN combustors for the CT and low-NO_x burners for duct firing are available, demonstrated, and technically feasible for CTs in either simple cycle or combined cycle configuration. The DLN combustion technology alone can achieve as low as 9 ppm (corrected to 15-percent O_2 dry conditions) when firing natural gas.

The technical evaluation of NO_xOUT, Thermal DeNO_x, NSCR, and indicate that these processes have not been applied to CT systems and are technically infeasible for the project because of process constraints (e.g., temperature). The SCONO$_x$™ control technology is available but not considered to be technically feasible because it has not been commercially demonstrated on large "F" Class CTs. The CTs planned for the project are General Electric Frame 7FA Units. The planned CTs have a nominal generating capacity of 170MW, which is at least seven times larger than the nominal 25-MW GE LM2500 utilized at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the SCONO$_x$™ technology are unknown given the large differences in machine flow rates. Additional concerns with the SCONO$_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, relatively brief operating history of the technology, and distillate oil firing. While the XONON™ catalytic combustion system is applied directly to the CT, application on a large combined cycle unit has not been demonstrated. For these reasons, the SCONO$_x$™ and XONON™ are still considered in the commercial demonstration stage.

SCR is commercially available, technically feasible. However, currently there are no known installations of "Hot SCR" on GE 7FA simple cycle CTs. Furthermore, with no known installations on GE7FA simple cycle turbines, long term effects on output degradation is uncertain and a concern.

For the proposed simple cycle CTs, the combination of DLN combustion technology and water injection is a technically feasible alternative that can achieve a maximum degree of emission reduction. The combined technology is capable of achieving a NO_x emission levels of 9 ppm when firing natural gas (corrected to 15-percent O_2 dry conditions) 42 ppm when firing light oil (corrected to 15-percent O_2 dry conditions).

Below is a summary of the technical availability, demonstration and feasibility for the proposed project:

Technology	Combined Cycle Status
Selective Catalytic Reduction	Technically Feasible, Not Demonstrated on GE 7FA
DLN Combustors	Available, Demonstrated and Feasible for gas firing
Wet Injection	Available, Demonstrated or Feasible for oil firing
$SCONO_x$	Available, Not Demonstrated
XOXON™	Not Demonstrated
Thermal De NO_x	Not Available or Feasible
NO_x Out	Not Available or Feasible
NSCR	Not Available or Feasible

SCR Cost Estimates

Tables B-4 and B-5 present the total capital and annualized costs of "Hot" SCR . The costs were developed using EPA Cost Control Manual (EPA; 1990, 1993) and vendor-based estimates. Standard EPA-recommended cost factors were used. A capital recovery period of 15 years was used for the capital costs.

Comparison of Economic, Environmental, and Energy Impacts

Table B-6 presents the potential emissions resulting from the formation of ammonium salts (i.e., particulate matter), and secondary emissions.

B.2.2 CARBON MONOXIDE

Identification of CO Control Technologies

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. Table B-3 presents a listing of LAER/BACT decisions for CO emissions from simple cycle CTs. Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence are required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with combustion controls alone. These installations have been required to use LAER technology and typically have CO limits less than 10 ppmvd (corrected to dry conditions).

Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with an efficiency of 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Oxidation Catalyst Costs

Tables B-7 and B-8 present the capital and annualized costs for an oxidation catalyst.

Table B-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides	0.43 lb/MW-hr for gas-firing and 1.3 lb/MW-hr for fuel oil firing
SO_2	Gases which contain SO_2 in excess of 110 nano-grams per Joule (ng/J) (0.90 lb/MW-hr) gross output or any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input

[a] Applicable to electric utility gas turbines with heat input at peak load (HHV) 850 MMBtu/hr

Source: 40 CFR 60 Subpart KKKK.

Table B-2 Summary of Best Available Control Technology (BACT) Determinations for Nitrogen Oxide (NOx) Emissions for Simple Cycle Combustion Turbines

Facility	State	Final Permit Issued	# of New MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	NOx Limit	Control Method	Avg. Time	Comments
South Eastern Energy Corp.	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 25 or 3.5 ppm	DLN if SC/SCR if CC		For NOx and CO: SC w/GE or SC w/SW501F or CC (either)
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	3.5 ppm (0.013 lb/mmBtu) CC; 9/12 ppm (0.033 lb/mmBtu) SC	SCR - CC, DLN-SC	an/1-hr	8 SC units and 2 CC units
Calhoun Power Company	AL	Jan-01	680	4	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 1,000 FO	0.033/0.044/0.055 lb/mmbtu NG; 0.163 lb/mmbtu (327 lb/hr) FO	DLN; WI		NOx-(annual avg./1-hr avg./peak mode)
Tenaska Alabama III Partners	AL	Jan-01	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		
ExxonMobil Production Co.	AL	Feb-05	15	2	0	Solar	NG	SC	8,760	25 ppm	DLN		1 CT on each of 2 Offshore Platforms
City of Lakeland, McIntosh Power Plant	FL	July-98	250	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm until 5/2002, 9 ppm after, 7.5 ppm if CC. NG; 42 ppm or 15 ppm FO	DLN or SCR; WI or SCR		Power Augmentation
Polk Power (TECO)	FL	Oct-99	330	2	0	GE 7 FA (165 MW)	NG; FO	SC	5,130; 750 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
Oleander Power	FL	Nov-99	950	5	0	GE 7FA (190 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Hardee Power Partners (TECO)	FL	Oct-99	75	1	0	GE 7EA (75 MW)	NG; FO	SC	8,760; 876 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Reliant Energy Osceola	FL	Dec-99	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,000; 2,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
Florida Power Corp., Intercession City	FL	Dec-99	261	3	0	GE 7EA (87 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Jacksonville Electric Authority - Brandy Branch	FL	Oct-99	510	3	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 800 FO	10.5 ppm NG; 42 ppm FO	DLN; WI		
IPS Avon Park Corp. - Vandola Power Project	FL	Dec-99	680	4	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Netting out of PSD for NOx and CO
IPS Avon Park - Shady Hills	FL	Jan-00	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Palmetto Power	FL	Jun-00	540	3	0	SW 501F (180 MW)	NG	SC	3,750	15 ppm	DLN		
Granite Power Partners	FL	Aug-00	540	3	0	GE/SW (180 MW)	NG; FO	SC	3,000; 500 FO	10.5/15/15 ppm NG; 42 ppm FO (GE only)	DLN		3 vendor options: GE 7FA (500 hr/yr FO)/SW 501F/SW 501D5A
IPS Avon Park Corp. - DeSoto Power Project	FL	Jun-00	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Florida Power & Light - Martin Power Plant	FL	Jul-00	340	2	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 500 FO	9/12/15 ppm NG; 42 ppm FO	DLN; WI		normal/power aug./peaking
Peace River Station	FL	Dec-00	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,390; 720 FO	9/10 ppm NG; 42 ppm FO	DLN; WI	3-hr test/rolling	
Florida Power & Light - Fort Myers	FL	Dec-00	340	2	0	GE 7FA (170 MW)	NG; FO	SC	8,760; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		netting out of NOx, CO, PM10 and SO2 review (subject to VOC review)
Duke Energy - Ft. Pierce	FL	Jun-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 1,000 FO	10.5 ppm NG; 42 ppm FO	DLN; WI	3-hr rolling	SCR - $50,602/ton NOx; CatOx - $21,832/ton CO&VOC
Pompano Beach Energy Center, LLC	FL	draft permit	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI		Hot SCR - $20,400/ton NOX; CatOx-$31,800/ton CO
Midway Development Center	FL	Feb-01	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1,500 FO	12 ppm NG (9 ppm on startup); 42 ppm FO	DLN; WI		Hot SCR - $20,700/ton NOX; CatOx-$31,800/ton CO
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	9 ppm /2.5 ppm NG; 36/10 ppm FO	DLN/SCR; WI	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG; FO	SC/CC	3,390/8,760; 720 FO	10 ppm (9 initial)/3.5 ppm NG; 42/15 ppm FO	DLN/SCR; WI	3-hr	1 SC CT and 1 CC CT also capable of operating in SC mode
Duke Energy Lake	FL	Jul-01	640	8	0	GE 7EA (80 MW)	NG	SC	2,500	12 ppm (9 ppm initial test)	DLN; WI	3-hr rolling	SCR - $15,000/ton NOx; CatOx - $5,563/ton CO
Deerfield Beach Energy Center	FL	draft permit	510	3	0	GE 7FA (170 MW)	NG; FO	SC	3,500; 1000 FO	9 ppm NG; 42 ppm FO	DLN; WI	24-hr	
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 3 SC; PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/9 ppm	SCR/DLN	24-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Fort Pierce Repowering Project	FL	Aug-01	180	1	1	SW 501F (180 MW)	NG; FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG; 12 ppm FO/25 ppm NG; 42 ppm FO	SCR/DLN; WI		CT will operate in both CC and SC modes
FPL Martin	FL	Apr-03	1,150	4	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 5000 FO/1,000; 500 FO	2.5 ppm NG; 10 ppm FO/9-15 ppm NG; 42 ppm FO	SCR/DLN; WI	24-hr	PA = Power Augmentation
FPL Manatee	FL	Apr-03	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	2.5 ppm CC/9-15 ppm SC	SCR/DLN	24-hr	PA = Power Augmentation
City of Tallahassee - Hopkins	FL	Oct-04	100	2	0	GE LM6000	NG; FO	SC	5,840; 4,000 FO	5 ppm	SCR	24-hr	
Seminole Electric Cooperative - Payne Creek	FL	draft	448	10	0	P&W FT-8 twin pacs	NG; FO	SC	2,500; 500 FO	25 ppm NG/42 ppm FO	WI	24-hr	
Keys Energy Services - Stock Island	FL	applic. under review	48	1	0	GE LM6000	FO	SC	4,000	42 ppm	WI	24-hr	
Shady Hills, Pasco County	FL	Jan-00	170			GE 7FA (170 MW)	FO	SC	see comment	9 ppmvd @ 15% O2 - 24 Hr CEMs	DLN	24-hr	1,000 hr/yr
Vandolah Hardee	FL	Nov-99	170			GE 7FA (170 MW)	FO	SC	see comment	9 ppmvd @ 15% O2 - 24 Hr CEMs	DLN	24-hr	1,000 hr/yr
JEA Baldwin	FL	Oct-99	170			GE 7FA (170 MW)	FO	SC	see comment	10.5 ppmvd @ 15% O2 - 24 Hr CEMs	DLN	24-hr	750 hr/yr
Reliant Osceola	FL	Nov-99	170			GE 7FA (170 MW)	FO	SC	see comment	10.5 ppmvd @ 15% O2 - 24 Hr CEMs	DLN	24-hr	750 hr/yr
Mid-GA	GA	Jun-99	119			119 MW WH 501D5A	FO	SC		9 ppmvd @15% O2	DLN/SCR		unknown
Tenaska Georgia Partners, L.P.	GA	Dec-98	960	6	0	GE 7FA (160 MW)	NG; FO	SC	3,066; 720 FO	15 ppm NG; 42 ppm FO	DLN; WI		
West Georgia Generating; Thomaston	GA	Jun-99	680	4	0	GE 7FA (170 MW)	NG; FO	SC	4,760; 1,687 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		
Heard County Power	GA	Oct-99	510	3	0	SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN		
Georgia Power, Jackson County	GA	Aug-99	1,216	16	0	GE 7EA (76 MW)	NG; FO	SC	4,000; 1,000 FO	12 ppm NG (15 ppm 30-day avg. for peak firing) ; 42 ppm FO	DLN; WI		
Duke Energy Sandersville, LLC	GA	Nov-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	10 ppm NG; 42 ppm FO	DLN; WI		Hot SCR - $36,520/ton NOx; CatOx - $8,330/ton CO
Oglethorpe Power Corp. - Talbot	GA	Aug-01	648	6	0	SW V84.2 (108 MW)	NG; FO	SC	8,760; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		Hot SCR - $9,381/ton NOx; CatOx - $3,980/ton CO
Effingham Power Co.	GA	Dec-01	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	12/3.5 ppm	DLN/SCR		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	draft permit	1,550	6	4	GE 7FA (170 MW)	NG	CC/SC	8,760/2,500	2.5/9.0 ppm	SCR/DLN	3-hr	

MEA of Georgia - W. R. Clayton	GA	draft permit	500	3	0	GE 7FA (170 MW)	NG; FO	SC	8,760; 1,500 FO	12 ppm NG; 42 ppm FO	DLN; WI	24-hr	Hot SCR - $14,100/ton NOx; CatOx - $15,000/ton CO
Calvert City	KY	1999 Draft	170			GE 7FA (170 MW)	FO	SC		25 ppmvd @ 15% O2	WI		unknown
Duke Energy - Marshall Co.	KY	draft permit	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12/9 ppm NG; 42 ppm FO	DLN; WI	1-hr/an	
Duke Energy Metcalfe	KY	draft permit	640	8	0	GE 7EA (80 MW)	NG	SC	2,500	12/9 ppm	DLN	1-hr/an	
East Kentucky Power Cooperative, Inc.	KY	Jul-01	240	3	0	GE 7EA (80 MW)	NG; FO	SC	8760; 8,760 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Louisville Gas & Electric - Trimble	KY	Jun-01	960	6	0	GE 7FA (160 MW)	NG	SC	8,760	12/9 ppm	DLN	1-hr/an	
Westlake Energy Corp.	KY	draft permit	520	2	2	"F" Class (180 MW)	NG	SC	8,760	4.5 ppm	SCR		
Summer Shade Development Co.	KY	applic. under review	680	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	DLN		
Dynegy - Riverside Generating	KY	applic. under review	850	5	0	SW 501FD (170 MW)	NG	SC	4,000	15 ppm	DLN/SCR		Modification to increase hours of operation - proposes 2 CTs w/Hot SCR
Duke Energy Southaven	MS	Aug-00	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500; 500 FO	12 ppm NG (15 ppm 3-hr avg.); 42 ppm FO	DLN; WI		
Warren Power LLC (revision)	MS	May-01	320	4	0	GE 7EA (80 MW)	NG	SC	2,000	12 ppm (9 ppm annual)	DLN	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
Duke Energy Enterprise	MS	May-01	160	2	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 500 FO	12 ppm NG; 42 ppm FO	DLN; WI		
MEP Clarksdale Power	MS	Apr-01	320	4	0	GE 7EA (80 MW)	NG	SC	8,760	9 ppm	DLN		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
TVA - Kemper CT Plant	MS	Jul-01	440	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		10% NG base mode, 10% NG peaking, 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
South Mississippi Electric Power Association	MS	May-02	250	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN	24-hr	
South Mississippi Electric Power Assn.	MS	draft	84	1	0	GE 7EA (83.5 MW)	NG	SC	5,500	9 ppm	DLN	3-hr	Hot SCR - $9,973/ton NOx; CatOx - $2,417/ton CO
Dynegy Reidsville	NC	Jun-99	180			180 MW WH 501F	FO	SC	see comment	15 ppmvd @15% O2 by 2002	DLN		1,000 hr/yr
CP&L Lee Plant - Wayne County	NC	Jul-98	680	4		GE 7241 (2) GE 7231 (2) 170 MW (180 mm btu/hr) each	NG	SC	2000 each ?	12 to 42 ppm depending on control, cell cell comments	DLN, WI	?	This was a permit that was reissued since source failed to meet 18 month begin construction deadline
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000; 1,000 FO	3.5/9 ppm NG: 13/42 ppm FO	SCR/DLN: SCR/WI	24-hr	Reconfiguration of facility: 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co.	NC	Nov-99	850	5	0	GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	9 ppm NG at startup/10.5 ppm long-term; 42 ppm FO	DLN; WI		
Rockingham Power (Dynegy)	NC	Jun-99	780	5	0	SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG until 4/01, 20 ppm until 4/02, 15 ppm after; 42 ppm FO	DLN; WI		
Fayetteville Generator	NC	Jan-02	500	2	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760; 1000 FO	2.5/9 ppm NG: 13/42 ppm FO	SCR/DLN: SCR/WI		
Duke Energy - Buck Steam Station	NC	Nov-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	9 ppm NG at startup, 10.5 ppm long-term; 42 ppm FO	DLN; WI	24-hr	
Entergy Power - Rowan Generating Facility	NC	Jan-02	930	6	0	GE 7FA (155 MW)	NG; FO	SC	4,400; 1,000 FO	10.5 ppm (9 ppm initially) NG; 42 ppm FO	DLN; WI	24-hr	Hot SCR - $13,049/ton NOx; CatOx - $8,204/ton CO
Santee Cooper, Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Broad River Energy (SkyGen)	SC	Dec-99	513	3	0	GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	9 ppm NG; 42 ppm FO	DLN; WI		
Broad River Energy (SkyGen)	SC	Dec-00	342	2	0	GE 7FA (171 MW)	NG	SC	3,000	9 ppm (12 ppm w/SI)	DLN		Steam Injection (SI)
Duke Power - Mill Creek (f/k/a/ RIPP)	SC	Nov-01	654	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	10.5 (9 initially) ppm NG; 42 ppm FO	DLN; WI	24-hr	
Greenville Generating	SC	draft prmt	930	6	0	GE 7FA (155 MW)	NG, FO	SC	3,400; 1,000 FO	9 ppm NG; 42 ppm FO	DLN; WI		Hot SCR - $13,909/ton NOx; CatOx - $8,204/ton CO
Broad River Energy Center (f/k/a Cherokee Falls)	SC	May-03	340	2	0	GE 7FA (170 MW)	NG, FO	SC	3,000	9 ppm (12 ppm w/PA); 42 ppm FO	DLN		Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO
GenPower Anderson - revision	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm	DLN		Temporary 4 month operating period - **Not Subject to *PSD Review for* CO, VOC or SO2
Santee Cooper Rainey Generating Station	SC	May-03	251	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	9 ppm	DLN		Hot SCR - $15,550/ton NOx; CatOx - $1,717/ton CO
TVA, Johnsonville Fossil Plant	TN	Jul-99	340	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		10% NG base mode, 10% NG peaking, 10% FO base
TVA, Gallatin Fossil Plant	TN	Jul-99	340	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	15 ppm NG; 42 ppm FO	DLN; WI		10% NG base mode, 10% NG peaking, 10% FO base
TVA, Lagoon Creek Plant	TN	Apr-00	1,760	16	0	GE 7EA (110 MW)	NG; FO	SC	see comment	12 ppm/127 TPY NG; 42 ppm FO	DLN; WI	30/15day	10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	3.5/9 ppm NG; 12/42 ppm FO	SCR/DLN: SCR/WI		

SC Natural Gas Range	9 - 15 ppmvd NOx
SC Fuel Oil Range	36- 42 ppmvd NOx

Table B-3 Summary of Best Available Control Technology (BACT) Determinations for Carbon Monoxide (CO) Emissions for Simple Cycle Combustion Turbines

Facility	State	Final Permit Issued	MW	# of CTs	# of DB	Turbine Model	Fuel	Mode	Hours	CO Limit	Control Method	Avg. Time	Comments
South Eastern Energy Corp	AL	Jan-01	1,500	6	6 if CC	GE 7FA or SW 501F	NG	SC or CC	8,760	9 or 19 or 22 ppm	GCP		For NOx and CO, SC w/GE or SC w/SW501F or CC (either)
Duke Energy - Alexander City	AL	Feb-01	1,260	10	2	GE 7FA & 7EA	NG	CC & SC	8,760 CC; 2,500 SC	0.059 lb/mmBtu (130 lb/hr) CC; 0.09 lb/mmBtu (80 lb/hr) SC	GCP		8 SC units and 2 CC units
Calhoun Power Company	AL	Jan-01	680	4	0	GE 7FA (170 MW)	NG; FO	SC	4,000; 1,000 FO	0.017/0.064/0.026 lb/mmbtu (NG/FO/peak)	GCP		
Tenaska Alabama III Partners	AL	Jan-01	510	3	0	GE 7FA (170 MW)	NG FO	SC	3,066 720 FO	15 ppm	GCP		
ExxonMobil Production Co	AL	Feb-05	15	2	0	Solar	NG	SC	8,760	50 ppm	GCP		1 CT on each of 2 Offshore Platforms
City of Lakeland McIntosh Power Plant	FL	July-98	250	1	0	SW 501G (230 MW)	NG; FO	SC (later CC)	7,008; 250 FO	25 ppm NG 90 ppm FO	GCP		Power Augmentation
Polk Power (TECO)	FL	Oct-99	330	2	0	GE 7 FA (165 MW)	NG FO	SC	5,130 750 FO	15 ppm NG 33 ppm FO	GCP		
Oleander Power	FL	Nov-99	950	5	0	GE 7FA (190 MW)	NG FO	SC	3,390 1,000 FO	12 ppm NG 20 ppm FO	GCP		
Hardee Power Partners (TECO)	FL	Oct-99	75	1	0	GE 7FA (75 MW)	NG FO	SC	8,760 876 FO	25 ppm NG 20 ppm FO	GCP		
Reliant Energy Osceola	FL	Dec-99	510	3	0	GE 7FA (170 MW)	NG FO	SC	3,000 2,000 FO	10.5 ppm NG 20 ppm FO	GCP		
Florida Power Corp - Intercession City	FL	Dec-99	261	3	0	GE 7EA (87 MW)	NG FO	SC	3,390 1,000 FO	25 ppm NG 20 ppm FO	GCP		
Jacksonville Electric Authority - Brandy Branch	FL	Oct-99	510	3	0	GE 7FA (170 MW)	NG FO	SC	4,000 800 FO	15 ppm NG 20 ppm FO	GCP		
IPS Avon Park Corp - Vandola Power Project	FL	Dec-99	680	4	0	GE 7FA (170 MW)	NG FO	SC	3,390 1,000 FO	12 ppm NG 20 ppm FO	GCP		Netting out of PSD for NOx and CO
IPS Avon Park - Shady Hills	FL	Jan-00	510	3	0	GE 7FA (170 MW)	NG FO	SC	3,390 1,000 FO	12 ppm NG 20 ppm FO	GCP		
Palmetto Power	FL	Jun-00	540	3	0	SW 501F (180 MW)	NG	SC	3,750	25 ppm (15 ppm after 1st yr.)	GCP		
Granite Power Partners	FL	Aug-00	540	3	0	GE/SW (180 MW)	NG, FO	SC	3,000, 500 FO	12/16/10 ppm NG, 20 ppm FO (GE only)	GCP		3 vendor options. GE 7FA (500 hr/yr FO)/SW 501F/SW 501D5A
IPS Avon Park Corp - DeSoto Power Project	FL	Jun-00	510	3	0	GE 7FA (170 MW)	NG FO	SC	3,390; 1,000 FO	12 ppm NG 20 ppm FO	GCP		
Florida Power & Light - Martin Power Plant	FL	Jul-00	340	2	0	GE 7FA (170 MW)	NG FO	SC	3,390 500 FO	9/15/20 ppm NG; 20 ppm FO	GCP		normal/power aug./peaking
Peace River Station	FL	Dec-00	510	3	0	GE 7FA (170 MW)	NG, FO	SC	3,390, 720 FO	8.2 ppm NG, 14.2 ppm FO	GCP	3-hr test	
Florida Power & Light - Fort Myers	FL	Dec-00	340	2	0	GE 7FA (170 MW)	NG, FO	SC	8,760, 500 FO	9 ppm NG, 20 ppm FO	GCP		netting out of NOx, CO, PM10 and SO2 review (subject to VOC review)
Duke Energy - Ft. Pierce	FL	Jan-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500, 1,000 FO	25 ppm NG; 20 ppm FO	GCP	3-hr test	SCR - $50,602/ton NOx, CatOx - $21,832/ton CO&VOC
Pompano Beach Energy Center, LLC	FL	draft permit	510	3	0	GE 7FA (170 MW)	NG, FO	SC	3,500; 1,500 FO	9 ppm NG, 20 ppm FO	GCP		Hot SCR - $20,400/ton NOX; CatOx - $31,800/ton CO
Midway Development Center	FL	Feb-01	510	3	0	GE 7FA (170 MW)	NG, FO	SC	3,500; 1,500 FO	9 ppm NG; 20 ppm FO	GCP		Hot SCR - $20,700/ton NOX; CatOx - $31,800/ton CO
South Pond Energy Park	FL	draft permit	600	3	0	GE 7FA (170 MW)	NG, FO	SC/CC	3,390/8,760, 720 FO	9 ppm NG, 20 ppm FO	GCP	3-hr	2 SC CT and 1 CC CT also capable of operating in SC mode
North Pond Energy Park	FL	applic. under review	430	2	0	GE 7FA (170 MW)	NG, FO	SC/CC	3,390/8,760; 720 FO	9 ppm NG; 20 ppm FO	GCP		1 SC CT and 1 CC CT also capable of operating in SC mode
Duke Energy Lake	FL	Jul-01	640	8	0	GE 7EA (80 MW)	NG	SC	2,500	20 ppm (25 ppm first year)	GCP	3-hr test	SCR - $15,000/ton NOx, CatOx - $5,563/ton CO
Broward Energy Center	FL	May-02	775	4	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	8 ppm (SC & CC); 12 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 3 SC, PA = Power Augmentation
Belle Glade Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm (CC)/8 ppm (SC), 14 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Manatee Energy Center	FL	Jan-02	600	3	0	GE 7FA (175 MW)	NG	CC/SC	8,760/5,000	2.5 ppm/8 ppm, 4 ppm (CC w/PA)	GCP	3-hr	1 CC w/unfired HRSG & 2 SC; PA = Power Augmentation
Fort Pierce Repowering Project	FL	Aug-01	180	1	1	SW 501F (180 MW)	NG, FO	CC/SC	8,760; 1,000 FO/2,000; 500 FO	3.5 ppm NG, 10 ppm FO/ 16 ppm NG, 50 ppm FO	GCP		CT will operate in both CC and SC modes
FPL Martin	FL	Apr-03	1,150	4	0	GE 7FA (170 MW)	NG, FO	CC/SC	8,760, 5000 FO/1,000; 500 FO	10 ppm NG/8 ppm NG (12 ppm w/PA), 15 ppm FO	GCP	24-hr	PA = Power Augmentation
FPL Manatee	FL	Apr-03	1,150	4	4	GE 7FA (170 MW)	NG	CC/SC	8,760/1,000	10 ppm NG/8 ppm NG (12 ppm w/PA)	GCP	24-hr	PA = Power Augmentation
City of Tallahassee - Hopkins	FL	Oct-04	100	2	0	GE LM6000	NG FO	SC	5,840 4,000 FO	6 ppm	CatOX	24-hr	
Seminole Electric Cooperative - Payne Creek	FL	draft	448	10	0	P&W FT-8 twin pacs	NG FO	SC	2,500, 500 FO		CatOX		Not subject to PSD for CO
Keys Energy Services - Stock Island	FL	applic. under review	48	1	0	GE LM6000	FO	SC	4,000		GCP		Not subject to PSD for CO
Shady Hills Pasco County	FL	Jan-00	170			GE 7FA (170 MW)	FO	SC	see comment	12 ppmvd @15% O2	DLN		1,000 hr/yr
Vandolah Hardee	FL	Nov-99	170			GE 7FA (170 MW)	FO	SC	see comment	12 ppmvd @15% O2	DLN		1,000 hr/yr
JEA Baldwin	FL	Oct-99	170			GE 7FA (170 MW)	FO	SC	see comment	12 ppmvd @15% O2	DLN		750 hr/yr
Reliant Osceola	FL	Nov-99	170			GE 7FA (170 MW)	FO	SC	see comment	10.5 ppmvd @15% O2	DLN		750 hr/yr
Mid-GA	GA	Jun-99	119			119 MW WH 501D5A	FO	SC		10 ppmvd @15% O2	DLN/SCR		unknown
Tenaska Georgia Partners, L.P.	GA	Dec-98	960	6	0	GE 7FA (160 MW)	NG, FO	SC	3,066, 720 FO	15 ppm NG 20 ppm FO	GCP		
West Georgia Generating: Thomaston	GA	Jun-99	680	4	0	GE 7FA (170 MW)	NG FO	SC	4,760, 1,687 FO	15 ppm NG 20 ppm FO	GCP		
Heard County Power	GA	Oct-99	510	3	0	SW 501FD (170 MW)	NG	SC	4,000	25 ppm	GCP		
Georgia Power, Jackson County	GA	Aug-99	1,216	16	0	GE 7EA (76 MW)	NG, FO	SC	4,000, 1,000 FO	0.101 lb/MMBtu NG; 0.046 lb/MMBtu FO	GCP		
Duke Energy Sandersville, LLC	GA	Nov-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	2,500, 500 FO	25 ppm NG, 20 ppm FO	GCP		Hot SCR - $36,520/ton NOx; CatOx - $8,330/ton CO
Oglethorpe Power Corp. - Talbot	GA	Aug-01	648	6	0	SW V84.2 (108 MW)	NG; FO	SC	8,760; 500 FO	15 ppm	GCP		Hot SCR - $9,381/ton NOx, CatOx - $3,980/ton CO
Effingham Power Co	GA	Dec-01	525	2	0	GE 7FA (170 MW)	NG	SC/CC	8,760	9 ppm	GCP		Initially SC, but later converting to CC
Peace Valley Generation Co., LLC	GA	draft permit	1,550	6	4	GE 7FA (170 MW)	NG	CC/SC	8,760/2,500	2.0 ppm/8.0 ppm	CatOx/GCP	3-hr	
MEA of Georgia - W. R. Clayton	GA	draft permit	500	3	0	GE 7FA (170 MW)	NG, FO	SC	8,760, 1,500 FO	13.1 ppm NG; 32.40 ppm FO	GCP	24-hr	Hot SCR - $14,100/ton NOx, CatOx - $15,000/ton CO
Duke Energy - Marshall Co	KY	draft permit	640	8	0	GE 7EA (80 MW)	NG, FO	SC	2,500 500 FO	20 ppm NG 25 ppm FO	GCP		
Duke Energy Metcalfe	KY	draft permit	640	8	0	GE 7EA (80 MW)	NG	SC	2,500	25 ppm	GCP	1-hr	
East Kentucky Power Cooperative, Inc	KY	Jul-01	240	3	0	GE 7EA (80 MW)	NG, FO	SC	8760 8,760 FO	25 ppm NG; 20 ppm FO	GCP		CatOx - $8,000/ton CO
Louisville Gas & Electric - Trimble	KY	Jun-01	960	6	0	GE 7FA (160 MW)	NG	SC	8,760	9 ppm	GCP	3-hr	
Westlake Energy Corp	KY	draft permit	520	2	2	"F" Class (180 MW)	NG	SC	8,760	17.2 ppm	GCP		
Summer Shade Development Co.	KY	applic. under review	680	4	0	GE 7FA (170 MW)	NG	SC	4,000	9 ppm	GCP		
Dynegy - Riverside Generating	KY	applic. under review	850	5	0	SW 501FD (170 MW)	NG	SC	4,000	118 lb/hour	GCP		Modification to increase hours of operation proposes 2 CTs w/Hot SCR
Calvert City	KY	1999 Draft	170			GE 7FA (170 MW)	FO	SC		30 ppmvd @15% O2 Baseload, 90 other	WI		unknown
Duke Energy Southaven	MS	Aug-00	640	8	0	GE 7EA (80 MW)	NG, FO	SC	2,500, 500 FO	20 ppm NG; 25 ppm FO	GCP		
Warren Power LLC (revision)	MS	May-01	320	4	0	GE 7EA (80 MW)	NG	SC	2,000	25 ppm	GCP	24-hr	revised to include startup/shutdown emissions in PTE and modeling analysis
Duke Energy Enterprise	MS	May-01	160	2	0	GE 7EA (80 MW)	NG, FO	SC	3,000, 500 FO	20 ppm NG, 25 ppm FO	GCP		

MEP Clarksdale Power	MS	Apr-01	320	4	0	GE 7EA (80 MW)	NG	SC	8,760	25 ppm	GCP		Hot SCR - $26,567/ton NOx; CatOx - $5,593/ton CO
TVA - Kemper CT Plant	MS	Jul-01	440	4	0	GE 7EA (110 MW)	NG; FO	SC	see comment	25 ppm NG; 20 ppm FO	GCP		*10% NG base mode, 10% NG peaking,* 10% FO base; Hot SCR - $13,668/ton NOx; CatOx - $8,036/ton CO
South Mississippi Electric Power Association	MS	May-02	250	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	25 ppm	GCP	3-hr	
South Mississippi Electric Power Assn	MS	draft	84	1	0	GE 7EA (83.5 MW)	NG	SC	5,500	20 ppm	GCP	3-hr	Hot SCR - $9,973/ton NOx; CatOx - $2,417/ton CO
CP&L Lee Plant - Wayne County	NC	Jul-98	680	4		GE 7241 (2) GE 7231 (2) 170 MW (180 mm btu/hr) each	NG	SC	2000 each ?	not given	not given		This was a permit that was reissued since source failed to meet 18 month begin construction deadline
Carolina Power & Light, Richmond Co. (2nd revision - new configuration)	NC	applic. under review	2,040	9	0	GE 7FA (170 MW)	NG; FO	CC/SC	8,760/2,000, 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Reconfiguration of facility; 6 CC and 3 SC CTs
Carolina Power & Light, Rowan Co	NC	Nov-99	850	5	0	GE 7FA (170 MW)	NG; FO	SC	2,000; 1,000 FO	15 ppm NG; 20 ppm FO	GCP		
Rockingham Power (Dynegy)	NC	Jun-99	780	5	0	SW 501F (156 MW)	NG; FO	SC	3,000; 1,000 FO	25 ppm NG; 50 ppm FO	GCP		
Fayetteville Generation	*NC*	*Jan-02*	*500*	*2*	*0*	*GE 7FA (170 MW)*	*NG; FO*	*CC/SC*	*8,760; 1000 FO*	*9 ppm NG; 20-41 ppm FO*	*GCP*		*CO level for FO depends on Load*
Duke Energy - Buck Steam Station	NC	Nov-01	640	8	0	GE 7EA (80 MW)	NG; FO	SC	3,000; 1000 FO	20 ppm NG; 25 ppm FO	GCP	3-hr	CatOx - $11,976/ton CO
Entergy Power - Rowan Generating Facility	NC	Jan-02	930	6	0	GE 7FA (155 MW)	NG; FO	SC	4,400; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		Hot SCR - $13,049/ton NOx; CatOx - $8,204/ton CO
Dynegy Reidsville	*NC*	*Jun-99*	*180*			*180 MW WH 501F*	*FO*	*SC*	*see comment*	*25 ppmvd @15% O2*	*DLN*		*1,000 hr/yr*
Santee Cooper Rainey Generating Station	SC	Apr-00	870	4	0	GE 7FA (170 MW)	NG, FO	2 CC, 2 SC	8,760; 1,000 FO	9 ppm NG; 20 ppm FO	GCP		
Broad River Energy (SkyGen)	SC	Dec-99	513	3	0	GE 7FA (171 MW)	NG, FO	SC	3,000; 500 FO	15 ppm NG; 20 ppm FO	GCP		
Broad River Energy (SkyGen)	SC	Dec-00	342	2	0	GE 7FA (171 MW)	NG	SC	3,000	9 ppm (15 ppm w/SI)	GCP		Steam Injection (SI)
Duke Power - Mill Creek (f/k/a RIPP)	SC	Nov-01	654	8	0	GE 7EA (80 MW)	NG, FO	SC	2,400; 1,000 FO	25 ppm NG; 20 ppm FO	GCP	24-hr	
Greenville Generating	SC	draft permit	930	6	0	GE 7FA (155 MW)	NG, FO	SC	3,400; 1,000 FO	9 ppm NG; 36 ppm FO	GCP		Hot SCR - $13,909/ton NOx; CatOx - $8,204/ton CO
Broad River Energy Center (f/k/a Cherokee Falls)	SC	May-03	340	2	0	GE 7FA (170 MW)	NG, FO	SC	3,000	9 ppm (15 ppm w/PA); 20 ppm FO	GCP		Hot SCR - $22,800/ton NOx; CatOx - $10,500/ton CO
GenPower Anderson - revision	SC	applic. under review	340	2	0	GE 7FA (170 MW)	NG	SC	2,928	9 ppm**	GCP		*Temporary 4 month operating period -* **Not Subject to PSD Review for CO, VOC or SO2
Santee Cooper Rainey Generating Station	SC	May-03	251	3	0	GE 7EA (83.5 MW)	NG	SC	8,760	25 ppm	GCP		Hot SCR - $15,550/ton NOx; CatOx - $1,717/ton CO
TVA, Johnsonville Fossil Plant	TN	Jul-99	340	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TVA, Gallatin Fossil Plant	TN	Jul-99	340	4	0	GE 7EA (85 MW)	NG; FO	SC	see comment	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base
TVA, Lagoon Creek Plant	TN	Apr-00	1,760	16	0	GE 7EA (110 MW)	NG; FO	SC	see comment	25 ppm NG; 20 ppm FO	GCP		10% NG base mode, 10% NG peaking, 10% FO base; 127 tpy of NOx is based on a 9 ppm
Southern Power Co.	TN	applic. under review	1,940	8	4	GE 7FA (170 MW)	NG; FO	CC/SC	8760; 1,000 FO	0.035 lb/mmbtu NG; 0.069 lb/mmbtu FO	GCP		

SC Natural Gas Range	8 -25 ppm CO
SC Fuel Oil Range	14.2 - 90 ppm CO

Table B-4. Capital Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
SCR Associated Equipment	$5,545,833	Vendor Estimate; Includes Cooling System
Ammonia Storage Tank	included	Vendor Estimate
Flue Gas Ductwork	included	Vendor Estimate
Instrumentation	included	Vendor Estimate
SCR Bypass Duct & Stack	$242,000	Engineering Estimate
Emission Monitoring	$277,292	5% of SCR Associated Equipment
Freight	$277,292	5% of SCR Associated Equipment
Total Direct Capital Costs (TDCC)	$6,342,417	
Direct Installation Costs		
Foundation and supports	$507,393	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$887,938	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$253,697	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping (Ammonia Injection Grid)	included	Vendor Estimate
Insulation for ductwork	$63,424	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$63,424	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation (General Facilities)	$317,121	5% of TDCC and RCC;OAQPS Cost Control Manual
Project Contingencies	$634,242	10% of TDCC and RCC;OAQPS Cost Control Manual
Total Direct Installation Costs (TDIC)	$2,727,239	
Total Capital Costs (TCC)	$9,069,656	Sum of TDCC and TDIC
Indirect Costs		
Engineering	included	Vendor Estimate
PSM/RMP Plan	$50,000	Engineering Estimate
Construction and Field Expense	$453,483	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$906,966	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$181,393	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$90,697	1% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInCC)	$1,682,538	
Total Direct, Indirect and Capital Costs (TDICC)	$10,752,194	Sum of TCC and TInCC

Table B-5. Annualized Cost for Selective Catalytic Reduction for General Electric Frame 7F Simple Cycle Operation

Cost Component	Costs	Basis of Cost Component
Direct Annual Costs		
Operating Personnel	$21,840	28 hours/week at $15/hr
Supervision	$3,276	15% of Operating Personnel;OAQPS Cost Control Manual
Ammonia	$52,545	$500 per ton for Aqueous NH_3 62 lb/hr, 3,390 hr/year
PSM/RMP Update	$25,000	Engineering Estimate
Inventory Cost	$11,072	Capital Recovery (10.98%) for 1/3 catalyst for SCR
Catalyst Cost	$75,625	4 years catalyst life; Based on Vendor Budget Estimate
Contingency	$5,681	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$195,038	
Energy Costs		
Electrical (SCR and Cooling)	$44,748	330kW/h for SCR system @ $0.04/kWh, 3,390 hr/yr
MW Loss and Heat Rate Penalty	$117,260	0.5% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TEC)	$162,008	
Indirect Annual Costs		
Overhead	$46,597	60% of Operating/Supervision Labor and Ammonia
Property Taxes	$107,522	1% of Total Capital Costs
Insurance	$107,522	1% of Total Capital Costs
Annualized Total Direct Capital	$1,180,591	10.98% Capital Recovery Factor of 7% over 15 years times sum c of TDICC
Total Indirect Annual Costs (TIAC)	$1,442,231	
Total Annualized Costs	$1,799,278	Sum of TDAC, TEC and TIAC
Incremental Cost Effectiveness(9 to 3 ppmvd)	$11,633	NO_x Reduction Only
	$16,114	Net Emission Reduction

Table B-6. Maximum Potential Incremental Emissions (TPY) with Selective Catalytic Reduction

Pollutants		Incremental Emissions (tons/year) of SCR Primary	Secondary	Total
Particulate		5.24	0.14	5.38
Sulfur Dioxide			0.05	0.05
Nitrogen Oxides		-154.67	2.62	-152.05
Carbon Monoxide			1.57	1.57
Volatile Organic Compounds			0.10	0.10
Ammonia		33.29		
	Total:	-116.14	4.48	-111.66
Carbon Dioxide (*additonal* from gas firing)			2,484.33	2,484.33

Basis:

Lost Energy (mmBtu/year)	39,226
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NO_x 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

Table B-7. Direct and Indirect Capital Costs for CO Catalyst, GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$693,555	Based on Vendor Quote and Construction Cost Index
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$69,356	10% of SCR Associated Equipment
Freight	$34,678	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$842,094	
Direct Installation Costs		
Foundation and supports	$67,368	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$117,893	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$33,684	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$16,842	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$8,421	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$8,421	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$257,628	
Total Capital Costs	$1,099,722	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$109,972	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$54,986	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$109,972	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$21,994	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$10,997	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$32,992	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$340,914	
Total Direct, Indirect and Capital Costs (TDICC)	$1,440,636	Sum of TCC and TInCC

Table B-8. Annualized Cost for CO Catalyst GE Frame 7FA in Combined Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate	
Diirect Annual Costs			
Operating Personnel	$6,240	8 hours/week at $15/hr	
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual	
Catalyst Replacement	$205,498	3 year catalyst life; base on Vendor Budget Quote	
Inventory Cost	$26,816	Capital Recovery (10.98%) for 1/3 catalyst	
Contingency	$7,185	3% of Direct Annual Costs	
Total Direct Annual Costs (TDAC)	$246,675		
Energy Costs			
Heat Rate Penalty	$83,552	0.2% of MW output; EPA, 1993 (Page 6-20) and $3/mmBtu addl fuel costs	
Total Energy Costs (TDEC)	$83,552		
Indirect Annual Costs			
Overhead	$4,306	60% of Operating/Supervision Labor	
Property Taxes	$14,406	1% of Total Capital Costs	
Insurance	$14,406	1% of Total Capital Costs	
Annualized Total Direct Capital	$158,182	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC	
Total Indirect Annual Costs	$191,300		
Total Annualized Costs	$521,527	Sum of TDAC, TEC and TIAC	
Cost Effectiveness	$9,214	per ton of CO Removed	56.60 tons/year CO Emissions Removed
	$11,483	per ton of Net Emission Reduction	

APPENDIX C

AERSURFACE MODEL OUTPUT

LCD ANNUAL SUMMARY FOR TAMPA INTERNATIONAL AIRPORT

AERSURFACE OUTPUT FOR AVERAGE MOISTURE CONDITIONS
12 WD SECTORS, MONTHLY FREQUENCIES

```
** Generated by AERSURFACE, dated 08009
** Center Latitude (decimal degrees):     27.962000
** Center Longitude (decimal degrees):   -82.540000
** Datum: NAD83
** Study radius (km) for surface roughness:   1.0
** Airport? Y, Continuous snow cover? N
** Surface moisture? Average, Arid region? N
** Month/Season assignments? User-specified
** Late autumn after frost and harvest, or winter with no snow: 12 1
2
** Winter with continuous snow on the ground: 0
** Transitional spring (partial green coverage, short annuals): 3 4 5
** Midsummer with lush vegetation: 6 7 8 9
** Autumn with unharvested cropland: 10 11
**
FREQ_SECT  MONTHLY 12
SECTOR    1    0   30
SECTOR    2   30   60
SECTOR    3   60   90
SECTOR    4   90  120
SECTOR    5  120  150
SECTOR    6  150  180
SECTOR    7  180  210
SECTOR    8  210  240
SECTOR    9  240  270
SECTOR   10  270  300
SECTOR   11  300  330
SECTOR   12  330  360
**            Month     Sect     Alb      Bo       Zo
  SITE_CHAR     1        1       0.15     0.47     0.027
  SITE_CHAR     1        2       0.15     0.47     0.031
  SITE_CHAR     1        3       0.15     0.47     0.040
  SITE_CHAR     1        4       0.15     0.47     0.021
  SITE_CHAR     1        5       0.15     0.47     0.071
  SITE_CHAR     1        6       0.15     0.47     0.038
  SITE_CHAR     1        7       0.15     0.47     0.095
  SITE_CHAR     1        8       0.15     0.47     0.052
  SITE_CHAR     1        9       0.15     0.47     0.048
  SITE_CHAR     1       10       0.15     0.47     0.054
  SITE_CHAR     1       11       0.15     0.47     0.058
  SITE_CHAR     1       12       0.15     0.47     0.031
  SITE_CHAR     2        1       0.15     0.47     0.027
  SITE_CHAR     2        2       0.15     0.47     0.031
  SITE_CHAR     2        3       0.15     0.47     0.040
  SITE_CHAR     2        4       0.15     0.47     0.021
  SITE_CHAR     2        5       0.15     0.47     0.071
  SITE_CHAR     2        6       0.15     0.47     0.038
  SITE_CHAR     2        7       0.15     0.47     0.095
  SITE_CHAR     2        8       0.15     0.47     0.052
```

SITE_CHAR	2	9	0.15	0.47	0.048
SITE_CHAR	2	10	0.15	0.47	0.054
SITE_CHAR	2	11	0.15	0.47	0.058
SITE_CHAR	2	12	0.15	0.47	0.031
SITE_CHAR	3	1	0.14	0.40	0.036
SITE_CHAR	3	2	0.14	0.40	0.038
SITE_CHAR	3	3	0.14	0.40	0.052
SITE_CHAR	3	4	0.14	0.40	0.034
SITE_CHAR	3	5	0.14	0.40	0.109
SITE_CHAR	3	6	0.14	0.40	0.083
SITE_CHAR	3	7	0.14	0.40	0.146
SITE_CHAR	3	8	0.14	0.40	0.063
SITE_CHAR	3	9	0.14	0.40	0.061
SITE_CHAR	3	10	0.14	0.40	0.068
SITE_CHAR	3	11	0.14	0.40	0.079
SITE_CHAR	3	12	0.14	0.40	0.039
SITE_CHAR	4	1	0.14	0.40	0.036
SITE_CHAR	4	2	0.14	0.40	0.038
SITE_CHAR	4	3	0.14	0.40	0.052
SITE_CHAR	4	4	0.14	0.40	0.034
SITE_CHAR	4	5	0.14	0.40	0.109
SITE_CHAR	4	6	0.14	0.40	0.083
SITE_CHAR	4	7	0.14	0.40	0.146
SITE_CHAR	4	8	0.14	0.40	0.063
SITE_CHAR	4	9	0.14	0.40	0.061
SITE_CHAR	4	10	0.14	0.40	0.068
SITE_CHAR	4	11	0.14	0.40	0.079
SITE_CHAR	4	12	0.14	0.40	0.039
SITE_CHAR	5	1	0.14	0.40	0.036
SITE_CHAR	5	2	0.14	0.40	0.038
SITE_CHAR	5	3	0.14	0.40	0.052
SITE_CHAR	5	4	0.14	0.40	0.034
SITE_CHAR	5	5	0.14	0.40	0.109
SITE_CHAR	5	6	0.14	0.40	0.083
SITE_CHAR	5	7	0.14	0.40	0.146
SITE_CHAR	5	8	0.14	0.40	0.063
SITE_CHAR	5	9	0.14	0.40	0.061
SITE_CHAR	5	10	0.14	0.40	0.068
SITE_CHAR	5	11	0.14	0.40	0.079
SITE_CHAR	5	12	0.14	0.40	0.039
SITE_CHAR	6	1	0.15	0.42	0.043
SITE_CHAR	6	2	0.15	0.42	0.044
SITE_CHAR	6	3	0.15	0.42	0.062
SITE_CHAR	6	4	0.15	0.42	0.044
SITE_CHAR	6	5	0.15	0.42	0.138
SITE_CHAR	6	6	0.15	0.42	0.127
SITE_CHAR	6	7	0.15	0.42	0.187
SITE_CHAR	6	8	0.15	0.42	0.070
SITE_CHAR	6	9	0.15	0.42	0.070
SITE_CHAR	6	10	0.15	0.42	0.076
SITE_CHAR	6	11	0.15	0.42	0.098
SITE_CHAR	6	12	0.15	0.42	0.047

SITE_CHAR	7	1	0.15	0.42	0.043
SITE_CHAR	7	2	0.15	0.42	0.044
SITE_CHAR	7	3	0.15	0.42	0.062
SITE_CHAR	7	4	0.15	0.42	0.044
SITE_CHAR	7	5	0.15	0.42	0.138
SITE_CHAR	7	6	0.15	0.42	0.127
SITE_CHAR	7	7	0.15	0.42	0.187
SITE_CHAR	7	8	0.15	0.42	0.070
SITE_CHAR	7	9	0.15	0.42	0.070
SITE_CHAR	7	10	0.15	0.42	0.076
SITE_CHAR	7	11	0.15	0.42	0.098
SITE_CHAR	7	12	0.15	0.42	0.047
SITE_CHAR	8	1	0.15	0.42	0.043
SITE_CHAR	8	2	0.15	0.42	0.044
SITE_CHAR	8	3	0.15	0.42	0.062
SITE_CHAR	8	4	0.15	0.42	0.044
SITE_CHAR	8	5	0.15	0.42	0.138
SITE_CHAR	8	6	0.15	0.42	0.127
SITE_CHAR	8	7	0.15	0.42	0.187
SITE_CHAR	8	8	0.15	0.42	0.070
SITE_CHAR	8	9	0.15	0.42	0.070
SITE_CHAR	8	10	0.15	0.42	0.076
SITE_CHAR	8	11	0.15	0.42	0.098
SITE_CHAR	8	12	0.15	0.42	0.047
SITE_CHAR	9	1	0.15	0.42	0.043
SITE_CHAR	9	2	0.15	0.42	0.044
SITE_CHAR	9	3	0.15	0.42	0.062
SITE_CHAR	9	4	0.15	0.42	0.044
SITE_CHAR	9	5	0.15	0.42	0.138
SITE_CHAR	9	6	0.15	0.42	0.127
SITE_CHAR	9	7	0.15	0.42	0.187
SITE_CHAR	9	8	0.15	0.42	0.070
SITE_CHAR	9	9	0.15	0.42	0.070
SITE_CHAR	9	10	0.15	0.42	0.076
SITE_CHAR	9	11	0.15	0.42	0.098
SITE_CHAR	9	12	0.15	0.42	0.047
SITE_CHAR	10	1	0.15	0.47	0.036
SITE_CHAR	10	2	0.15	0.47	0.038
SITE_CHAR	10	3	0.15	0.47	0.053
SITE_CHAR	10	4	0.15	0.47	0.038
SITE_CHAR	10	5	0.15	0.47	0.133
SITE_CHAR	10	6	0.15	0.47	0.123
SITE_CHAR	10	7	0.15	0.47	0.177
SITE_CHAR	10	8	0.15	0.47	0.066
SITE_CHAR	10	9	0.15	0.47	0.063
SITE_CHAR	10	10	0.15	0.47	0.070
SITE_CHAR	10	11	0.15	0.47	0.090
SITE_CHAR	10	12	0.15	0.47	0.039
SITE_CHAR	11	1	0.15	0.47	0.036
SITE_CHAR	11	2	0.15	0.47	0.038
SITE_CHAR	11	3	0.15	0.47	0.053
SITE_CHAR	11	4	0.15	0.47	0.038

SITE_CHAR	11	5	0.15	0.47	0.133
SITE_CHAR	11	6	0.15	0.47	0.123
SITE_CHAR	11	7	0.15	0.47	0.177
SITE_CHAR	11	8	0.15	0.47	0.066
SITE_CHAR	11	9	0.15	0.47	0.063
SITE_CHAR	11	10	0.15	0.47	0.070
SITE_CHAR	11	11	0.15	0.47	0.090
SITE_CHAR	11	12	0.15	0.47	0.039
SITE_CHAR	12	1	0.15	0.47	0.027
SITE_CHAR	12	2	0.15	0.47	0.031
SITE_CHAR	12	3	0.15	0.47	0.040
SITE_CHAR	12	4	0.15	0.47	0.021
SITE_CHAR	12	5	0.15	0.47	0.071
SITE_CHAR	12	6	0.15	0.47	0.038
SITE_CHAR	12	7	0.15	0.47	0.095
SITE_CHAR	12	8	0.15	0.47	0.052
SITE_CHAR	12	9	0.15	0.47	0.048
SITE_CHAR	12	10	0.15	0.47	0.054
SITE_CHAR	12	11	0.15	0.47	0.058
SITE_CHAR	12	12	0.15	0.47	0.031

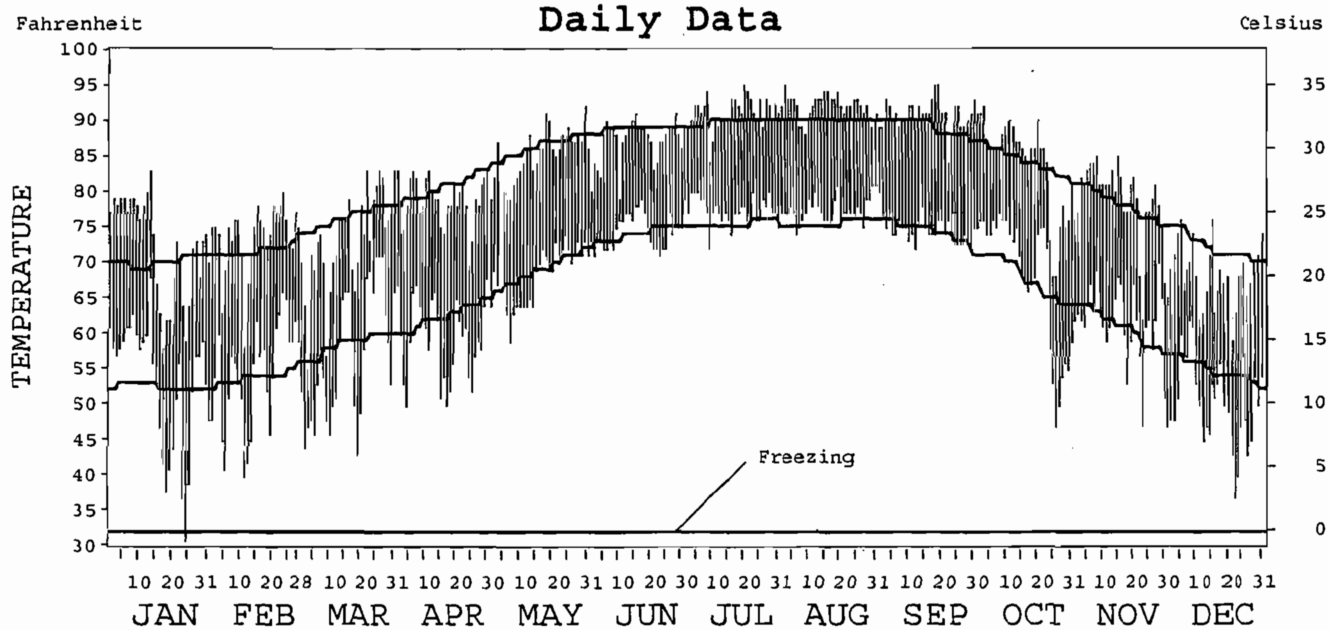
2005 LOCAL CLIMATOLOGICAL DATA

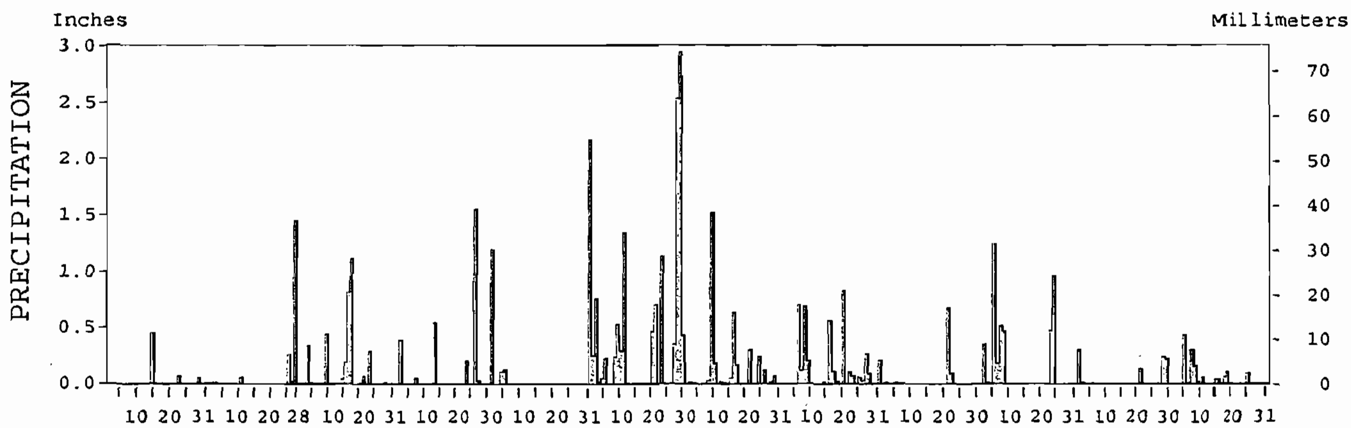
ANNUAL SUMMARY WITH COMPARATIVE DATA

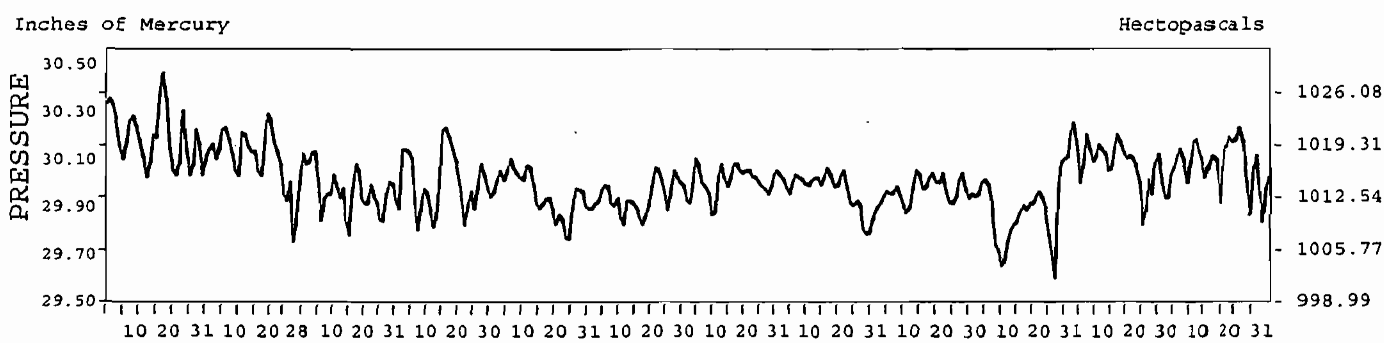
ISSN 0198-1307

TAMPA, FLORIDA (TPA)

Daily Data







I CERTIFY THAT THIS IS AN OFFICIAL PUBLICATION OF THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION, AND IS COMPILED FROM RECORDS ON FILE AT THE NATIONAL CLIMATIC DATA CENTER. Thomas R Karl

NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION

NATIONAL ENVIRONMENTAL SATELLITE, DATA, AND INFORMATION SERVICE

NATIONAL CLIMATIC DATA CENTER ASHEVILLE, NORTH CAROLINA

DIRECTOR NATIONAL CLIMATIC DATA CENTER

METEOROLOGICAL DATA FOR 2005

TAMPA, FL (TPA)

LATITUDE: 27° 57′ 41″ N | LONGITUDE: 82° 32′ 25″ W | ELEVATION (FT): GRND: 8 BARO: 40 | TIME ZONE: EASTERN (UTC + 5) | WBAN: 12842

	ELEMENT	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F	MEAN DAILY MAXIMUM	72.1	73.5	73.1	78.6	84.9	87.0	91.0	92.0	90.8	83.9	78.9	68.2	81.2
	HIGHEST DAILY MAXIMUM	83	80	83	83	92	91	95	95	95	92	85	76	95
	DATE OF OCCURRENCE	13	23	31+	30+	30	28+	20	02	19+	03	15+	15+	SEP 19+
	MEAN DAILY MINIMUM	53.0	54.4	57.1	59.4	68.3	74.4	77.3	77.5	75.0	68.1	61.8	50.4	64.7
	LOWEST DAILY MINIMUM	31	40	43	50	59	71	72	74	72	47	47	37	31
	DATE OF OCCURRENCE	24	11	19	17+	07	23+	09	06	29+	26	23	22	JAN 24
	AVERAGE DRY BULB	62.6	64.0	65.1	69.0	76.6	80.7	84.2	84.8	82.9	76.0	70.4	59.3	73.0
	MEAN WET BULB	57.2	57.6	59.4	61.0	69.0	74.6	76.7	77.0	74.2	68.6	63.8	54.4	66.1
	MEAN DEW POINT	53.2	53.0	54.7	55.1	64.9	72.3	73.8	74.3	70.7	64.6	59.7	50.1	62.2
	NUMBER OF DAYS WITH:													
	MAXIMUM ≥ 90°	0	0	0	0	3	4	25	27	23	5	0	0	87
	MAXIMUM ≤ 32°	0	0	0	0	0	0	0	0	0	0	0	0	0
	MINIMUM ≤ 32°	1	0	0	0	0	0	0	0	0	0	0	0	1
	MINIMUM ≤ 0°	0	0	0	0	0	0	0	0	0	0	0	0	0
H/C	HEATING DEGREE DAYS	131	71	93	13	0	0	0	0	0	13	18	176	515
	COOLING DEGREE DAYS	61	47	103	143	366	479	601	619	547	362	186	7	3521
RH	MEAN (PERCENT)	75	72	73	64	70	79	74	75	71	72	72	74	73
	HOUR 01 LST	86	82	83	74	79	87	83	82	81	82	80	83	82
	HOUR 07 LST	87	85	83	78	82	87	84	84	84	84	83	83	84
	HOUR 13 LST	59	56	57	48	56	68	62	62	56	56	58	59	58
	HOUR 19 LST	73	68	71	59	64	75	70	74	67	68	68	72	69
S	PERCENT POSSIBLE SUNSHINE	77	75	68	89	82	73	88	88	90	86		61	
W/O	NUMBER OF DAYS WITH:													
	HEAVY FOG(VISBY ≤ 1/4 MI)	3	1	1	0	0	0	0	0	0	0	2	0	7
	THUNDERSTORMS	0	0	1	2	2	12	15	18	3	3	0	0	56
CLOUDINESS	SUNRISE-SUNSET: (OKTAS)													
	CEILOMETER (≤ 12,000 FT.)													
	SATELLITE (> 12,000 FT.)													
	MIDNIGHT-MIDNIGHT: (OKTAS)													
	CEILOMETER (≤ 12,000 FT.)													
	SATELLITE (> 12,000 FT.)													
	NUMBER OF DAYS WITH:													
	CLEAR													
	PARTLY CLOUDY													
	CLOUDY													
PR	MEAN STATION PRESS. (IN.)	30.19	30.10	29.97	29.99	29.95	29.94	30.01	29.96	29.97	29.90	30.06	30.08	30.01
	MEAN SEA-LEVEL PRESS. (IN.)	30.20	30.11	29.98	30.00	29.96	29.94	30.01	29.97	29.97	29.91	30.07	30.09	30.02
WINDS	RESULTANT SPEED (MPH)	1.5	0.8	2.3	0.9	1.5	1.3	0.7	0.3	3.1	3.2	2.4	2.5	0.8
	RES. DIR. (TENS OF DEGS.)	02	30	24	28	29	04	23	15	09	03	03	02	02
	MEAN SPEED (MPH)	6.3	6.8	7.5	8.4	6.8	6.1	6.1	5.5	7.0	7.4	7.3	6.9	6.8
	PREVAIL.DIR.(TENS OF DEGS.)	01	06	20	03	28	27	25	23	06	04	04	04	04
	MAXIMUM 2-MINUTE WIND:													
	SPEED (MPH)	23	28	31	35	26	23	31	30	22	35	30	22	35
	DIR. (TENS OF DEGS.)	34	22	24	20	22	13	14	31	12	35	29	33	35
	DATE OF OCCURRENCE	23	27	08	07	31	21	09	07	21+	24	21	26	OCT 24
	MAXIMUM 5-SECOND WIND:													
	SPEED (MPH)	30	33	40	46	37	31	43	38	29	44	40	26	46
	DIR. (TENS OF DEGS.)	34	22	24	20	21	10	14	31	10	36	29	34	20
	DATE OF OCCURRENCE	23	27	08	07	31	23+	09	07	21+	24	21	26	APR 07
PRECIPITATION	WATER EQUIVALENT:													
	TOTAL (IN.)	0.57	1.80	3.32	2.76	3.61	12.26	3.38	4.09	0.79	4.20	0.90	1.27	38.95
	GREATEST 24-HOUR (IN.)	0.45	1.47	1.87	1.58	2.17	3.39	1.56	0.89	0.73	1.44	0.46	0.46	3.39
	DATE OF OCCURRENCE	14	26-27	16-17	26-27	31	29-30	09-10	08-09	21-22	23-24	28-29	07-08	JUN 29-30
	NUMBER OF DAYS WITH:													
	PRECIPITATION ≥ 0.01	3	5	11	6	4	16	14	16	4	8	5	10	102
	PRECIPITATION ≥ 0.10	1	2	6	4	4	14	7	10	1	7	4	4	64
	PRECIPITATION ≥ 1.00	0	1	1	1	2	4	1	0	0	1	0	0	11
SNOWFALL	SNOW,ICE PELLETS,HAIL:													
	TOTAL (IN.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	GREATEST 24-HOUR (IN.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	DATE OF OCCURRENCE													
	MAXIMUM SNOW DEPTH (IN.)	0	0	0	0	0	0	0	0	0	0	0	0	0
	DATE OF OCCURRENCE													
	NUMBER OF DAYS WITH:													
	SNOWFALL ≥ 1.0	0	0	0	0	0	0	0	0	0	0	0	0	0

NORMALS, MEANS, AND EXTREMES

TAMPA, FL (TPA)

LATITUDE:	LONGITUDE:	ELEVATION (FT):		TIME ZONE:	WBAN: 12842
27° 57' 41" N	82° 32' 25" W	GRND: 8	BARO: 40	EASTERN (UTC + 5)	

	ELEMENT	POR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
TEMPERATURE °F	NORMAL DAILY MAXIMUM	30	70.1	71.6	76.3	80.6	86.3	88.9	89.7	90.0	89.0	84.1	78.0	72.0	81.4
	MEAN DAILY MAXIMUM	58	70.4	72.3	76.4	81.7	87.4	89.9	90.3	90.4	89.0	84.0	77.5	72.0	81.8
	HIGHEST DAILY MAXIMUM	59	86	88	91	93	98	99	97	98	96	94	90	86	99
	YEAR OF OCCURRENCE		2002	1971	1949	1975	1975	1985	1995	1975	1991	1990	1971	1994	JUN 1985
	MEAN OF EXTREME MAXS.	58	80.6	82.3	85.3	88.6	93.0	94.6	94.6	94.4	93.4	90.3	85.3	82.0	88.7
	NORMAL DAILY MINIMUM	30	52.4	53.8	58.5	62.4	68.9	74.0	75.3	75.4	74.3	67.6	60.7	54.7	64.8
	MEAN DAILY MINIMUM	58	50.3	52.2	56.9	61.5	67.9	72.7	74.4	74.5	73.0	66.2	57.9	52.2	63.3
	LOWEST DAILY MINIMUM	59	21	24	29	40	49	53	63	67	57	40	23	18	18
	YEAR OF OCCURRENCE		1985	1958	1980	1987	1992	1984	1970	1973	1981	1964	1970	1962	DEC 1962
	MEAN OF EXTREME MINS.	58	32.5	36.3	41.2	48.3	58.1	66.9	70.4	70.6	67.5	52.7	41.8	34.7	51.8
	NORMAL DRY BULB	30	61.3	62.7	67.4	71.5	77.6	81.5	82.5	82.7	81.6	75.8	69.3	63.3	73.1
	MEAN DRY BULB	58	60.3	62.2	66.9	71.6	77.5	81.3	82.3	82.3	81.0	75.1	67.8	62.1	72.5
	MEAN WET BULB	21	56.0	58.3	61.3	64.7	70.5	74.9	76.1	76.3	74.9	69.3	63.5	55.0	66.7
	MEAN DEW POINT	21	52.1	53.9	56.9	59.9	66.3	72.0	73.8	74.1	72.5	65.9	60.0	51.2	63.2
	NORMAL NO. DAYS WITH:														
	MAXIMUM ≥ 90°	30	0.0	0.0	0.0	0.7	8.5	17.4	21.8	22.3	16.4	2.9	*	0.0	90.0
	MAXIMUM ≤ 32°	30	0.0	*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	MINIMUM ≤ 32°	30	1.3	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7	2.7
	MINIMUM ≤ 0°	30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
H/C	NORMAL HEATING DEG. DAYS	30	187	136	63	13	0	0	0	0	0	4	44	144	591
	NORMAL COOLING DEG. DAYS	30	57	59	124	204	393	501	550	549	489	323	157	76	3482
RH	NORMAL (PERCENT)	30	76	74	72	70	71	75	77	79	79	76	76	77	75
	HOUR 01 LST	30	85	84	83	82	82	85	86	88	88	86	86	86	85
	HOUR 07 LST	30	87	87	87	86	85	86	88	90	91	90	88	88	88
	HOUR 13 LST	30	60	57	55	52	54	60	64	65	63	58	59	61	59
	HOUR 19 LST	30	74	70	68	64	64	70	74	76	76	73	74	75	72
S	PERCENT POSSIBLE SUNSHINE	52	64	65	71	75	75	67	62	62	62	65	64	61	66
W/O	MEAN NO. DAYS WITH:														
	HEAVY FOG(VISBY≤1/4 MI)	59	4.9	2.8	2.5	1.1	0.4	0.3	0.1	0.2	0.3	1.0	2.5	3.2	19.3
	THUNDERSTORMS	59	1.1	1.7	2.6	2.6	4.9	13.8	20.1	19.7	10.9	2.8	1.2	1.2	82.6
CLOUDINESS	MEAN:														
	SUNRISE-SUNSET (OKTAS)														
	MIDNIGHT-MIDNIGHT (OKTAS)														
	MEAN NO. DAYS WITH:														
	CLEAR	1	1.0	2.0	9.0		9.0	9.0							
	PARTLY CLOUDY	1	1.0	2.0	3.0		10.0	9.0							
	CLOUDY	1	3.0	1.0	8.0		2.0	5.0							
PR	MEAN STATION PRESSURE(IN)	31	30.12	30.09	30.05	30.02	29.99	30.01	30.05	30.02	29.99	30.01	30.07	30.11	30.04
	MEAN SEA-LEVEL PRES. (IN)	21	30.12	30.11	30.06	30.03	30.01	30.01	30.06	30.02	29.99	30.01	30.08	30.13	30.05
WINDS	MEAN SPEED (MPH)	53	8.5	8.9	9.4	9.1	8.6	7.9	7.2	7.0	7.6	8.1	8.3	8.2	8.2
	PREVAIL.DIR(TENS OF DEGS)	37	06	06	09	09	27	27	27	09	07	06	03	04	09
	MAXIMUM 2-MINUTE:														
	SPEED (MPH)	10	44	36	31	44	36	30	37	30	45	40	35	43	45
	DIR. (TENS OF DEGS)		32	28	24	28	25	27	26	31	35	21	19	32	35
	YEAR OF OCCURRENCE		1999	1998	2005	1997	1999	2003	2004	2005	2004	1996	2000	2004	SEP 2004
	MAXIMUM 5-SECOND:														
	SPEED (MPH)	10	51	44	40	49	47	47	47	43	54	53	41	52	54
	DIR. (TENS OF DEGS)		32	09	24	28	34	13	20	12	35	21	17	31	35
	YEAR OF OCCURRENCE		1999	1998	2005	1997	1997	1996	2001	1996	2004	1996	2000	2004	SEP 2004
PRECIPITATION	NORMAL (IN)	30	2.27	2.67	2.84	1.80	2.85	5.50	6.49	7.60	6.54	2.29	1.62	2.30	44.77
	MAXIMUM MONTHLY (IN)	59	8.02	10.82	12.64	10.71	17.64	13.75	20.59	18.59	13.98	7.36	6.12	15.57	20.59
	YEAR OF OCCURRENCE		1948	1998	1959	1997	1979	1974	1960	1949	1979	1952	1963	1997	JUL 1960
	MINIMUM MONTHLY (IN)	59	T	0.21	0.06	T	0.02	1.46	1.65	2.35	0.79	0.06	T	0.07	T
	YEAR OF OCCURRENCE		1950	1950	1956	1981	2001	1997	1981	1952	2005	2000	1960	1984	APR 1981
	MAXIMUM IN 24 HOURS (IN)	59	3.81	4.41	5.20	5.44	11.84	5.53	12.11	5.37	8.45	2.93	4.48	4.76	12.11
	YEAR OF OCCURRENCE		1996	1998	1960	1997	1979	1974	1960	1949	1997	1985	1988	1997	JUL 1960
	NORMAL NO. DAYS WITH:														
	PRECIPITATION ≥ 0.01	30	7.1	6.4	6.6	4.7	6.2	11.7	14.9	16.0	12.4	6.5	5.5	6.3	104.3
	PRECIPITATION ≥ 1.00	30	0.5	0.7	0.8	0.4	0.6	1.6	1.8	2.5	2.3	0.8	0.3	0.6	12.9
SNOWFALL	NORMAL (IN)	30	0.*	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.*	0.0
	MAXIMUM MONTHLY (IN)	59	0.2	T	T	T	0.0	0.0	T	0.0	0.0	0.0	0.0	T	0.2
	YEAR OF OCCURRENCE		1977	1951	1980	1997			1998					1989	JAN 1977
	MAXIMUM IN 24 HOURS (IN)	59	0.2	T	T	T	0.0	0.0	T	0.0	0.0	0.0	0.0	T	0.2
	YEAR OF OCCURRENCE		1977	1951	1980	1997			1998					1989	JAN 1977
	MAXIMUM SNOW DEPTH (IN)	57	0	0	0	0	0	0	0	0	0	0	0	0	0
	YEAR OF OCCURRENCE														
	NORMAL NO. DAYS WITH:														
	SNOWFALL ≥ 1.0	30	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

PRECIPITATION (inches) 2005 TAMPA, FL (TPA)

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
1976	0.40	0.49	1.64	1.83	8.13	7.22	4.58	7.02	6.04	1.30	1.59	2.05	42.29
1977	2.75	2.41	0.73	0.86	0.73	2.66	5.36	5.98	4.28	0.42	1.89	3.40	31.47
1978	2.82	5.17	2.44	0.94	5.00	2.03	5.85	5.97	3.08	3.42	0.01	3.12	39.85
1979	5.72	2.87	2.43	0.55	17.64	2.07	5.93	12.76	13.98	0.16	0.83	1.52	66.46
1980	1.72	2.01	3.09	4.38	3.94	3.81	5.66	7.62	4.05	1.27	2.68	0.37	40.60
1981	0.44	5.34	1.70	T	1.68	9.37	1.65	7.71	5.87	0.87	0.43	3.58	38.64
1982	1.86	2.09	2.99	1.87	5.90	8.34	10.49	7.20	10.76	2.17	0.85	1.29	55.81
1983	1.25	7.35	7.59	2.76	4.10	7.17	6.37	8.89	6.61	1.74	2.33	4.71	60.87
1984	1.62	3.32	1.31	1.51	3.19	3.24	7.15	5.68	4.21	0.29	0.72	0.07	32.31
1985	2.06	2.07	1.80	0.96	0.22	6.43	6.48	8.65	9.04	4.77	0.99	1.13	44.60
1986	2.37	1.49	4.27	0.95	2.46	5.00	6.24	5.46	3.87	6.21	1.33	1.95	41.60
1987	3.29	1.50	12.01	0.39	2.86	3.39	6.06	8.50	4.76	1.46	4.36	0.50	49.08
1988	2.76	1.44	4.09	1.83	1.27	5.19	3.40	11.09	13.56	0.09	5.97	1.64	52.33
1989	1.54	0.41	1.79	0.71	0.24	7.41	8.86	7.90	6.11	1.89	2.05	4.72	43.63
1990	0.53	4.58	1.71	1.47	1.76	5.16	10.01	3.27	2.42	2.63	0.66	0.19	34.39
1991	2.41	0.41	4.73	1.54	6.88	3.78	9.92	7.35	3.43	0.78	1.26	0.67	43.16
1992	1.47	3.67	0.95	2.17	0.10	7.03	2.80	8.22	2.95	2.20	2.43	0.99	34.98
1993	3.60	2.32	3.93	2.45	1.74	3.18	2.92	5.06	6.60	4.23	0.22	1.28	37.53
1994	3.68	0.43	0.66	3.43	0.07	5.98	11.31	8.37	8.20	3.29	0.24	1.57	47.23
1995	3.51	2.02	2.02	1.48	1.67	9.79	10.12	13.75	2.80	4.71	1.24	1.02	54.13
1996	5.42	3.04	4.65	4.20	1.45	8.96	2.72	7.39	5.44	3.12	0.91	2.11	49.41
1997	0.95	0.66	1.28	10.71	1.70	1.46	6.73	8.20	12.84	4.20	3.41	15.57	67.71
1998	4.64	10.82	5.16	0.41	1.96	2.65	12.95	6.55	8.42	0.47	0.40	0.92	55.35
1999	3.04	0.29	0.72	0.40	1.52	4.65	3.65	8.35	6.05	2.85	1.78	1.02	34.32
2000	1.95	0.30	0.41	0.43	0.02	4.53	8.14	5.44	5.14	0.06	2.04	1.39	29.85
2001	1.03	1.18	6.73	0.02	T	6.81	6.01	2.83	11.76	2.39	0.10	0.89	39.75
2002	2.49	2.84	0.63	1.84	1.07	11.57	7.33	8.82	7.51	2.11	1.76	14.10	62.07
2003	0.11	2.90	3.94	4.19	2.50	13.19	3.63	14.90	4.01	0.46	0.86	1.30	51.99
2004	3.73	4.02	1.11	2.04	1.44	9.01	10.19	14.03	9.77	1.70	0.73	1.54	59.31
2005	0.57	1.80	3.32	2.76	3.61	12.26	3.38	4.09	0.79	4.20	0.90	1.27	38.95
POR= 115 YRS	2.30	2.79	3.01	2.08	2.90	6.87	7.50	7.94	6.49	2.58	1.61	2.21	48.28

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AVERAGE TEMPERATURE (°F) 2005 TAMPA, FL (TPA)

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
1976	56.6	63.1	70.5	70.6	76.1	79.0	81.7	81.6	79.3	71.0	62.8	59.6	71.0
1977	51.2	57.5	70.9	71.5	76.5	83.7	82.9	83.0	82.3	72.5	67.7	58.7	71.5
1978	55.0	53.2	64.2	72.3	78.7	82.4	83.0	82.8	81.4	75.1	71.7	66.2	72.2
1979	57.8	59.3	65.4	74.2	75.9	80.8	83.9	82.2	81.9	75.2	68.7	63.0	72.4
1980	62.0	56.6	68.1	70.1	77.2	81.6	84.0	83.0	81.3	74.0	66.4	57.5	71.8
1981	50.4	61.4	62.8	72.4	75.4	81.5	82.5	81.7	78.6	74.5	64.4	59.2	70.4
1982	59.8	67.9	68.1	71.4	74.4	81.5	82.1	82.1	80.2	74.3	70.8	67.6	73.4
1983	58.9	60.3	63.3	68.6	76.8	80.9	82.2	82.2	79.4	75.8	65.9	59.9	71.2
1984	58.0	62.6	66.0	71.0	78.0	80.4	81.5	82.4	79.9	75.7	64.9	67.3	72.3
1985	55.9	63.6	69.4	72.5	79.8	83.7	82.4	83.1	80.5	79.2	73.6	59.0	73.6
1986	59.3	65.0	65.4	69.1	77.4	81.8	83.0	82.6	82.3	76.8	76.3	66.5	73.8
1987	59.2	63.2	66.4	66.4	77.8	82.7	83.1	83.7	81.4	71.3	68.9	64.3	72.4
1988	58.6	59.1	65.6	70.6	75.3	81.0	82.7	82.9	82.0	73.5	70.8	63.0	72.1
1989	67.1	64.9	69.8	72.0	78.4	82.4	83.3	83.0	82.4	75.4	68.9	56.2	73.7
1990	66.1	69.2	69.7	72.1	80.5	82.7	82.5	83.9	82.8	77.6	70.2	66.9	75.4
1991	66.7	64.2	68.4	76.8	81.2	81.3	82.3	83.2	81.9	75.3	65.8	64.6	74.3
1992	59.8	63.6	64.8	69.4	74.3	82.1	83.8	82.4	82.0	72.7	70.0	64.3	72.4
1993	67.0	60.2	64.3	67.2	76.1	81.8	83.8	83.7	81.9	75.8	69.1	59.5	72.5
1994	60.6	66.9	68.0	75.4	78.2	82.6	81.7	81.7	80.2	76.5	72.4	65.1	74.1
1995	58.8	61.4	68.7	73.5	81.8	80.2	83.0	83.3	82.0	77.8	65.2	61.0	73.1
1996	59.2	60.0	62.4	70.4	79.3	80.9	83.7	83.2	82.0	75.8	68.1	63.5	72.4
1997	62.6	68.6	73.9	71.6	77.7	81.8	82.7	82.8	81.7	74.7	66.8	61.3	73.9
1998	63.6	62.5	64.6	72.3	79.2	85.6	83.5	83.6	81.7	77.5	72.5	68.0	74.6
1999	63.8	64.2	65.1	74.3	77.8	81.2	83.6	83.7	80.9	76.3	68.9	63.2	73.6
2000	61.3	63.7	71.0	71.6	80.3	82.4	82.1	82.8	82.3	74.3	66.7	60.3	73.2
2001	55.2	68.2	65.7	72.7	77.4	82.2	82.1	83.2	79.3	75.1	71.3	68.8	73.4
2002	63.1	62.4	69.7	76.3	79.9	81.4	82.3	82.4	82.8	78.9	65.7	60.1	73.8
2003	54.8	63.3	71.7	72.1	80.0	81.7	82.7	81.9	81.3	76.9	71.4	59.8	73.1
2004	59.6	63.0	68.0	70.2	78.9	83.3	82.7	82.3	81.2	76.8	70.2	61.3	73.1
2005	62.6	64.0	65.1	69.0	76.6	80.7	84.2	84.8	82.9	76.0	70.4	59.3	73.0
POR= 115 YRS	60.8	62.4	66.8	71.4	77.0	80.8	81.1	82.1	80.7	74.7	67.4	62.2	72.3

HEATING DEGREE DAYS (base 65°F) 2005 TAMPA, FL (TPA)

YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1976-77	0	0	0	11	122	208	422	214	28	6	0	0	1011
1977-78	0	0	0	18	53	222	320	323	99	4	0	0	1039
1978-79	0	0	0	0	2	75	245	190	53	0	0	0	565
1979-80	0	0	0	0	47	112	136	262	64	8	0	0	629
1980-81	0	0	0	1	65	233	447	127	103	2	0	0	978
1981-82	0	0	0	0	83	223	209	24	53	8	0	0	600
1982-83	0	0	0	12	18	95	218	148	103	20	0	0	614
1983-84	0	0	0	0	57	214	252	115	68	5	0	0	711
1984-85	0	0	0	0	87	61	306	119	17	5	0	0	595
1985-86	0	0	0	0	9	238	185	78	105	7	0	0	622
1986-87	0	0	0	0	0	53	202	88	42	64	0	0	449
1987-88	0	0	0	4	46	107	221	195	85	14	0	0	672
1988-89	0	0	0	0	9	127	41	116	45	7	0	0	345
1989-90	0	0	0	17	27	285	70	32	13	5	0	0	449
1990-91	0	0	0	7	11	70	72	84	46	0	0	0	290
1991-92	0	0	0	0	93	94	179	90	69	32	5	0	562
1992-93	0	0	0	0	57	83	58	137	84	24	0	0	443
1993-94	0	0	0	6	44	185	158	62	50	5	0	0	510
1994-95	0	0	0	0	7	81	200	151	23	1	0	0	463
1995-96	0	0	0	0	83	180	198	188	152	16	0	0	817
1996-97	0	0	0	3	36	101	132	39	0	7	0	0	318
1997-98	0	0	0	7	36	163	108	103	113	4	0	0	534
1998-99	0	0	0	0	4	56	118	97	44	6	5	0	330
1999-00	0	0	0	5	20	110	154	99	3	10	0	0	401
2000-01	0	0	0	3	61	212	318	48	60	8	0	0	710
2001-02	0	0	0	9	0	65	165	100	43	0	0	0	382
2002-03	0	0	0	0	84	174	311	87	11	16	0	0	683
2003-04	0	0	0	0	21	175	195	110	29	15	0	0	545
2004-05	0	0	0	0	7	160	131	71	93	13	0	0	475
2005-	0	0	0	13	18	176							

WBAN : 12842

COOLING DEGREE DAYS (base 65°F) 2005 TAMPA, FL (TPA)

YEAR	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	ANNUAL
1976	17	63	199	175	348	424	525	517	440	202	63	45	3018
1977	2	9	218	210	364	567	559	565	526	258	139	36	3453
1978	18	0	79	232	431	529	565	557	500	319	208	121	3559
1979	28	36	73	283	344	482	592	543	515	322	164	55	3437
1980	45	22	164	165	386	506	598	564	493	284	115	7	3349
1981	0	32	43	230	331	501	552	525	414	303	71	49	3051
1982	56	114	156	208	299	499	537	537	467	311	197	182	3563
1983	36	24	57	137	369	487	540	541	439	342	91	64	3127
1984	42	52	104	190	410	468	517	546	454	337	92	135	3347
1985	30	88	163	237	464	569	547	566	475	445	275	58	3917
1986	15	85	123	139	391	510	565	551	526	374	348	107	3734
1987	27	43	91	114	405	538	567	583	497	207	169	91	3332
1988	30	32	110	188	326	489	554	562	517	271	191	74	3344
1989	112	120	202	224	425	528	575	564	529	344	151	18	3792
1990	107	154	164	225	487	537	549	592	541	406	176	139	4077
1991	131	68	158	361	509	498	543	572	515	326	126	88	3895
1992	25	55	70	170	301	519	589	544	518	248	212	72	3323
1993	126	12	72	95	352	511	593	587	513	347	174	21	3403
1994	32	118	148	321	415	535	524	524	461	364	233	91	3766
1995	15	59	145	264	526	464	561	574	518	405	95	63	3689
1996	27	50	76	182	450	482	589	570	516	348	135	63	3488
1997	62	145	283	213	397	510	556	559	508	314	97	55	3699
1998	75	41	107	229	446	623	582	583	506	394	236	160	3982
1999	85	84	52	294	409	492	583	589	481	363	144	62	3638
2000	48	68	197	213	482	529	537	558	524	300	121	71	3648
2001	22	141	92	245	393	522	536	571	434	326	196	187	3665
2002	114	34	192	347	466	499	543	544	541	437	114	28	3859
2003	2	48	226	236	473	505	553	532	495	375	219	19	3683
2004	33	58	130	179	440	553	558	542	493	371	169	53	3579
2005	61	47	103	143	366	479	601	619	547	362	186	7	3521

SNOWFALL (inches) 2005 TAMPA, FL (TPA)

YEAR	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	TOTAL
1976-77	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.2
1977-78	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1978-79	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1979-80	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	T	0.0	0.0	0.0	T
1980-81	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1981-82	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1982-83	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1983-84	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1984-85	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1985-86	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986-87	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987-88	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988-89	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989-90	0.0	0.0	0.0	0.0	0.0	T	0.0	0.0	0.0	0.0	0.0	0.0	T
1990-91	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991-92	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1992-93	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1993-94	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994-95	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995-96	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996-97	0.0	0.0	0.0	0.0	0.0	0.0	T	0.0	0.0	T	0.0	0.0	T
1997-98	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1998-99	T	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	T
1999-00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2000-01	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2001-02	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2002-03	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2003-04	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2004-05	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2005-	0.0	0.0	0.0	0.0	0.0	0.0							
POR= 58 YRS	0.0	0.0	0.0	0.0	0.0	T	0.0	T	T	0.0	0.0	0.0	T

WBAN : 12842

REFERENCE NOTES:

PAGE 1:
THE TEMPERATURE GRAPH SHOWS NORMAL MAXIMUM AND NORMAL MINIMUM DAILY TEMPERATURES (SOLID CURVES) AND THE ACTUAL DAILY HIGH AND LOW TEMPERATURES (VERTICAL BARS).

PAGE 2 AND 3:
H/C INDICATES HEATING AND COOLING DEGREE DAYS.
RH INDICATES RELATIVE HUMIDITY
W/O INDICATES WEATHER AND OBSTRUCTIONS
S INDICATES SUNSHINE.
PR INDICATES PRESSURE.
CLOUDINESS ON PAGE 3 IS THE SUM OF THE CEILOMETER AND SATELLITE DATA NOT TO EXCEED EIGHT EIGHTHS(OKTAS).

GENERAL:
T INDICATES TRACE PRECIPITATION, AN AMOUNT GREATER THAN ZERO BUT LESS THAN THE LOWEST REPORTABLE VALUE.
+ INDICATES THE VALUE ALSO OCCURS ON EARLIER DATES.
BLANK ENTRIES DENOTE MISSING OR UNREPORTED DATA.
NORMALS ARE 30-YEAR AVERAGES (1971 - 2000).
ASOS INDICATES AUTOMATED SURFACE OBSERVING SYSTEM.
PM INDICATES THE LAST DAY OF THE PREVIOUS MONTH.
POR (PERIOD OF RECORD) BEGINS WITH THE JANUARY DATA MONTH AND IS THE NUMBER OF YEARS USED TO COMPUTE THE MEAN. INDIVIDUAL MONTHS WITHIN THE POR MAY BE MISSING.
WHEN THE POR FOR A NORMAL IS LESS THAN 30 YEARS, THE NORMAL IS PROVISIONAL AND IS BASED ON THE NUMBER OF YEARS INDICATED.
0.* OR * INDICATES THE VALUE OR MEAN-DAYS-WITH IS BETWEEN 0.00 AND 0.05.
CLOUDINESS FOR ASOS STATIONS DIFFERS FROM THE NON-ASOS OBSERVATION TAKEN BY A HUMAN OBSERVER. ASOS STATION CLOUDINESS IS BASED ON TIME-AVERAGED CEILOMETER DATA FOR CLOUDS AT OR BELOW 12,000 FEET AND ON SATELLITE DATA FOR CLOUDS ABOVE 12,000 FEET.
THE NUMBER OF DAYS WITH CLEAR, PARTLY CLOUDY, AND CLOUDY CONDITIONS FOR ASOS STATIONS IS THE SUM OF THE CEILOMETER AND SATELLITE DATA FOR THE SUNRISE TO SUNSET PERIOD.

GENERAL CONTINUED:
CLEAR INDICATES 0 - 2 OKTAS, PARTLY CLOUDY INDICATES 3 - 6 OKTAS, AND CLOUDY INDICATES 7 OR 8 OKTAS. WHEN AT LEAST ONE OF THE ELEMENTS (CEILOMETER OR SATELLITE) IS MISSING, THE DAILY CLOUDINESS IS NOT COMPUTED.
WIND DIRECTION IS RECORDED IN TENS OF DEGREES (2 DIGITS) CLOCKWISE FROM TRUE NORTH. "00" INDICATES CALM. "36" INDICATES TRUE NORTH.
RESULTANT WIND IS THE VECTOR AVERAGE OF THE SPEED AND DIRECTION.
AVERAGE TEMPERATURE IS THE SUM OF THE MEAN DAILY MAXIMUM AND MINIMUM TEMPERATURE DIVIDED BY 2.
SNOWFALL DATA COMPRISE ALL FORMS OF FROZEN PRECIPITATION, INCLUDING HAIL.
A HEATING (COOLING) DEGREE DAY IS THE DIFFERENCE BETWEEN THE AVERAGE DAILY TEMPERATURE AND 65° F.
DRY BULB IS THE TEMPERATURE OF THE AMBIENT AIR.
DEW POINT IS THE TEMPERATURE TO WHICH THE AIR MUST BE COOLED TO ACHIEVE 100 PERCENT RELATIVE HUMIDITY.
WET BULB IS THE TEMPERATURE THE AIR WOULD HAVE IF THE MOISTURE CONTENT WAS INCREASED TO 100 PERCENT RELATIVE HUMIDITY.

ON JULY 1, 1996, THE NATIONAL WEATHER SERVICE BEGAN USING THE "METAR" OBSERVATION CODE THAT WAS ALREADY EMPLOYED BY MOST OTHER NATIONS OF THE WORLD. THE MOST NOTICEABLE DIFFERENCE IN THIS ANNUAL PUBLICATION WILL BE THE CHANGE IN UNITS FROM TENTHS TO EIGHTS(OKTAS) FOR REPORTING THE AMOUNT OF SKY COVER.

2005
TAMPA,
FLORIDA (TPA)

Tampa is on west central coast of the Florida Peninsula. Very near the Gulf of Mexico at the upper end of Tampa Bay, land and sea breezes modify the subtropical climate. Major rivers flowing into the area are the Hillsborough, the Alafia, and the Little Manatee.

Winters are mild. Summers are long, rather warm, and humid. Low temperatures are about 50 degrees in the winter and 70 degrees during the summer. Afternoon highs range from the low 70s in the winter to around 90 degrees from June through September. Invasions of cold northern air produce an occasional cool winter morning. Freezing temperatures occur on one or two mornings per year during December, January, and February. In some years no freezing temperatures occur. Temperatures rarely fail to recover to the 60s on the cooler winter days. Temperatures above the low 90s are uncommon because of the afternoon sea breezes and thunderstorms. An outstanding feature of the Tampa climate is the summer thunderstorm season. Most of the thunderstorms occur in the late afternoon hours from June through September. The resulting sudden drop in temperature from about 90 degrees to around 70 degrees makes for a pleasant change. Between a dry spring and a dry fall, some 30 inches of rain, about 60 percent of the annual total, falls during the summer months. Snowfall is very rare. Measurable snows under 1/2 inch have occurred only a few times in the last one hundred years.

A large part of the generally flat sandy land near the coast has an elevation of under 15 feet above sea level. This does make the area vulnerable to tidal surges. Tropical storms threaten the area on a few occasions most years. The greatest risk of hurricanes has been during the months of June and October. Many hurricanes, by replenishing the soil moisture and raising the water table, do far more good than harm. The heaviest rains in a 24-hour period, around 12 inches, have been associated with hurricanes.

Fittingly named the Suncoast, the sun shines more than 65 percent of the possible, with the sunniest months being April and May. Afternoon humidities are usually 60 percent or higher in the summer months, but range from 50 to 60 percent the remainder of the year.

Night ground fogs occur frequently during the cooler winter months. Prevailing winds are easterly, but westerly afternoon and early evening sea breezes occur most months of the year. Winds in excess of 25 mph are not common and usually occur only with thunderstorms or tropical disturbances.

Based on the 1951-1980 period, the average first occurrence of 32 degrees Fahrenheit in the fall is December 26 and the average last occurrence in the spring is February 3.

STATION LOCATION

TAMPA, FLORIDA

LOCATION	Occupied From	Occupied To	Airline Distances and Directions from previous Location	LATITUDE NORTH	LONGITUDE WEST	ELEVATION ABOVE: SEA LEVEL: GROUND TEMPERATURE SITE	GROUND: WIND INSTRUMENT	EXTREME THERMOMETERS	PSYCHROMETER	SUNSHINE SWITCH	TIPPING BUCKET RAIN GAGE	WEIGHING RAIN GAGE	8 INCH RAIN GAGE	HYGROTHERMOMETER	AUTOMATIC OBSERVING EQUIPMENT *	REMARKS
*NOTE:																
AIRPORT																
2222 N. Westshore Blvd. Tampa International Airport	10/1/75	12/7/81	1/2 mi. S	27°58'	82°32'	19	e22		5	5	5		3	e5		e. Same site as prior to 10/1/75. Station type changed from WSMO to WSCMO 12/13/78.
Hangar One Tampa International Airport	12/7/81	11/01/95	0.5 mi. N.	27°58'	82°32'	19	22		f35	f52	f35		f35	5 g5		f. Moved to new location 12/1/81. g. Type change 8/1985.
International Airport	11/01/95	Present	NA	27°58'	82°32'	h8									S	ASOS Commissioned 11/01/95 h. Ground elevation.

* TYPE

M = AMOS
T = AUTOB
S = ASOS
W = AWOS

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* NOTES: For earlier station history see previous edition.

APPENDIX D

BPIP MODEL INPUT AND OUTPUT FILES

FIGURE 1. BUILDING, SOURCE, AND PROPERTY BOUNDARY LOCATIONS

FIGURE 2. RECEPTOR GRID FOR SIGNIFICANT IMPACT ANALYSIS

BPIP INPUT

```
'Shady Hills\Lakes\sh0308.isc'
'P'
'METERS'  1.00000000
'UTMY'  0.0000
10
'INFILT1'  1          15.240
    4         14.326
           347218.197     3138573.480
           347218.197     3138582.541
           347231.556     3138582.541
           347231.556     3138573.480
'TURB1'  1          15.540
    4          6.706
           347232.798     3138503.788
           347232.798     3138512.314
           347240.148     3138512.314
           347240.148     3138503.788
'TURB2'  1          15.580
    4          6.706
           347278.613     3138503.788
           347278.613     3138512.314
           347285.963     3138512.314
           347285.963     3138503.788
'TURB3'  1          15.830
    4          6.706
           347324.032     3138504.229
           347324.032     3138512.754
           347331.382     3138512.754
           347331.382     3138504.229
'TURB4'  1          16.190
    4          6.706
           347377.404     3138503.568
           347377.404     3138512.093
           347384.753     3138512.093
           347384.753     3138503.568
'TURB5'  1          15.290
    4          6.706
           347425.483     3138504.450
           347425.483     3138512.975
           347432.832     3138512.975
           347432.832     3138504.450
'INTAKE2'  1          15.280
    4         14.326
           347264.230     3138572.984
           347264.230     3138582.045
           347277.589     3138582.045
           347277.589     3138572.984
'INTAKE3'  1          15.840
    4         14.326
```

```
             347310.444     3138573.480
             347310.444     3138582.541
             347323.803     3138582.541
             347323.803     3138573.480
'INTAKE4'    1         16.130
    4            14.326
             347363.108     3138572.984
             347363.108     3138582.045
             347376.467     3138582.045
             347376.467     3138572.984
'INTAKE5'    1         16.240
    4            14.326
             347410.810     3138573.480
             347410.810     3138582.541
             347424.169     3138582.541
             347424.169     3138573.480
10
'CT1'            15.540        22.860      347236.538      3138500.539
'CT2'            15.660        22.860      347282.120      3138500.420
'CT3'            16.030        22.860      347327.855      3138500.379
'CT4'            15.990        22.860      347380.860      3138500.455
'CT5'            15.340        22.860      347429.354      3138500.417
'HEATER1'           15.540          9.144      347229.420      3138502.750
'HEATER2'           15.610          9.144      347275.179      3138502.183
'HEATER3'           15.960          9.144      347320.996      3138501.899
'HEATER4'           16.130          9.144      347374.331      3138501.899
'HEATER5'           15.360          9.144      347422.843      3138502.041
```

BPIP OUTPUT

BPIP (Dated: 04274)

DATE : 3/19/2008

TIME : 14:31:40

S:\Projects\GE Energy\Shady Hills\Lakes\sh0308.isc

============================

BPIP PROCESSING INFORMATION:

============================

The P flag has been set for preparing downwash related data for a model run utilizing the PRIME algorithm.

Inputs entered in METERS will be converted to meters using a conversion factor of 1.0000. Output will be in meters.

The UTMP variable is set to UTMY. The input is assumed to be in UTM coordinates. BPIP will move the UTM origin to the first pair of UTM coordinates read. The UTM coordinates of the new origin will be subtracted from all the other UTM coordinates entered to form this new local coordinate system.

Plant north is set to 0.00 degrees with respect to True North.

S:\Projects\GE Energy\Shady Hills\Lakes\sh0308.isc

PRELIMINARY* GEP STACK HEIGHT RESULTS TABLE
(Output Units: meters)

Stack Name	Stack Height	Stack-Building Base Elevation Differences	GEP** EQN1	Preliminary* GEP Stack Height Value
CT1	22.86	0.00	16.76	65.00
CT2	22.86	0.08	16.68	65.00
CT3	22.86	0.20	16.56	65.00
CT4	22.86	-0.20	16.97	65.00
CT5	22.86	0.05	16.72	65.00
HEATER1	9.14	0.30	35.51	65.00
HEATER2	9.14	0.33	35.49	65.00
HEATER3	9.14	0.13	16.64	65.00
HEATER4	9.14	0.00	35.82	65.00
HEATER5	9.14	0.07	16.69	65.00

* Results are based on Determinants 1 & 2 on pages 1 & 2 of the GEP Technical Support Document. Determinant 3 may be investigated for additional stack height credit. Final values result after Determinant 3 has been taken into consideration.

** Results were derived from Equation 1 on page 6 of GEP Technical Support Document. Values have been adjusted for any stack-building base elevation differences.

Note: Criteria for determining stack heights for modeling emission limitations for a source can be found in Table 3.1 of the GEP Technical Support Document.

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DATE : 3/19/2008
TIME : 14:31:40

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BPIP output is in meters

SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT1	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDWID	CT1	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT1	10.53	9.67	8.53	9.67	10.53	11.06
SO	BUILDWID	CT1	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDWID	CT1	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT1	10.53	9.67	8.53	9.67	10.53	11.06
SO	BUILDWID	CT1	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDLEN	CT1	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT1	9.82	8.72	7.35	8.72	9.82	10.63
SO	BUILDLEN	CT1	11.11	11.26	11.06	10.53	9.67	8.53
SO	BUILDLEN	CT1	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT1	9.82	8.72	7.35	8.72	9.82	10.63
SO	BUILDLEN	CT1	11.11	11.26	11.06	10.53	9.67	8.53
SO	XBADJ	CT1	2.55	1.77	0.94	0.08	-0.78	-1.61
SO	XBADJ	CT1	-2.40	-3.12	-3.74	-5.73	-7.54	-9.13
SO	XBADJ	CT1	-10.43	-11.42	-12.07	-12.34	-12.25	-11.78
SO	XBADJ	CT1	-12.22	-12.30	-12.00	-11.34	-10.33	-9.01
SO	XBADJ	CT1	-7.42	-5.60	-3.61	-2.99	-2.28	-1.50
SO	XBADJ	CT1	-0.68	0.17	1.01	1.82	2.57	3.25
SO	YBADJ	CT1	1.37	2.63	3.81	4.88	5.80	6.54
SO	YBADJ	CT1	7.08	7.41	7.51	7.39	7.04	6.47
SO	YBADJ	CT1	5.71	4.78	3.70	2.51	1.24	-0.07
SO	YBADJ	CT1	-1.37	-2.63	-3.81	-4.88	-5.80	-6.54
SO	YBADJ	CT1	-7.08	-7.41	-7.51	-7.39	-7.04	-6.47
SO	YBADJ	CT1	-5.71	-4.78	-3.70	-2.51	-1.24	0.07

SO	BUILDHGT	CT2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT2	6.71	6.71	0.00	6.71	6.71	6.71
SO	BUILDHGT	CT2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT2	6.71	6.71	0.00	6.71	6.71	6.71
SO	BUILDHGT	CT2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDWID	CT2	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT2	10.53	9.67	0.00	9.67	10.53	11.06
SO	BUILDWID	CT2	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDWID	CT2	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT2	10.53	9.67	0.00	9.67	10.53	11.06
SO	BUILDWID	CT2	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDLEN	CT2	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT2	9.82	8.72	0.00	8.72	9.82	10.63
SO	BUILDLEN	CT2	11.11	11.26	11.06	10.53	9.67	8.53
SO	BUILDLEN	CT2	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT2	9.82	8.72	0.00	8.72	9.82	10.63
SO	BUILDLEN	CT2	11.11	11.26	11.06	10.53	9.67	8.53
SO	XBADJ	CT2	2.71	1.97	1.16	0.33	-0.52	-1.35
SO	XBADJ	CT2	-2.14	-2.87	0.00	-5.52	-7.36	-8.98
SO	XBADJ	CT2	-10.33	-11.37	-12.05	-12.38	-12.32	-11.89
SO	XBADJ	CT2	-12.38	-12.49	-12.22	-11.58	-10.59	-9.28
SO	XBADJ	CT2	-7.68	-5.85	0.00	-3.20	-2.46	-1.64
SO	XBADJ	CT2	-0.78	0.11	1.00	1.85	2.65	3.37
SO	YBADJ	CT2	1.16	2.45	3.67	4.78	5.74	6.52
SO	YBADJ	CT2	7.11	7.49	0.00	7.54	7.23	6.69
SO	YBADJ	CT2	5.95	5.03	3.96	2.77	1.49	0.17
SO	YBADJ	CT2	-1.16	-2.45	-3.67	-4.78	-5.74	-6.52
SO	YBADJ	CT2	-7.11	-7.49	0.00	-7.54	-7.23	-6.69
SO	YBADJ	CT2	-5.95	-5.03	-3.96	-2.77	-1.49	-0.17

SO	BUILDHGT	CT3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT3	6.71	6.71	0.00	6.71	6.71	6.71
SO	BUILDHGT	CT3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	CT3	6.71	6.71	0.00	6.71	6.71	6.71
SO	BUILDHGT	CT3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDWID	CT3	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT3	10.52	9.67	0.00	9.67	10.52	11.06
SO	BUILDWID	CT3	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDWID	CT3	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	CT3	10.52	9.67	0.00	9.67	10.52	11.06
SO	BUILDWID	CT3	11.26	11.11	10.63	9.82	8.72	7.35
SO	BUILDLEN	CT3	9.67	10.52	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT3	9.82	8.72	0.00	8.72	9.82	10.63
SO	BUILDLEN	CT3	11.11	11.26	11.06	10.52	9.67	8.52
SO	BUILDLEN	CT3	9.67	10.52	11.06	11.26	11.11	10.63
SO	BUILDLEN	CT3	9.82	8.72	0.00	8.72	9.82	10.63
SO	BUILDLEN	CT3	11.11	11.26	11.06	10.52	9.67	8.53
SO	XBADJ	CT3	3.13	2.31	1.42	0.49	-0.45	-1.39
SO	XBADJ	CT3	-2.28	-3.10	0.00	-5.91	-7.82	-9.50
SO	XBADJ	CT3	-10.88	-11.94	-12.63	-12.94	-12.85	-12.37
SO	XBADJ	CT3	-12.80	-12.83	-12.48	-11.75	-10.66	-9.24

SO XBADJ	CT3	-7.55	-5.62	0.00	-2.80	-2.00	-1.13
SO XBADJ	CT3	-0.23	0.68	1.57	2.41	3.18	3.85
SO YBADJ	CT3	1.55	2.91	4.18	5.33	6.31	7.10
SO YBADJ	CT3	7.67	8.01	0.00	7.96	7.57	6.95
SO YBADJ	CT3	6.12	5.10	3.93	2.64	1.26	-0.15
SO YBADJ	CT3	-1.55	-2.91	-4.18	-5.33	-6.31	-7.10
SO YBADJ	CT3	-7.67	-8.01	0.00	-7.96	-7.57	-6.95
SO YBADJ	CT3	-6.12	-5.10	-3.93	-2.64	-1.26	0.15

SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDWID	CT4	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	CT4	10.52	9.67	8.53	9.67	10.52	11.06
SO BUILDWID	CT4	11.25	11.11	10.63	9.82	8.72	7.35
SO BUILDWID	CT4	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	CT4	10.52	9.67	8.53	9.67	10.52	11.06
SO BUILDWID	CT4	11.25	11.11	10.63	9.82	8.72	7.35
SO BUILDLEN	CT4	9.67	10.52	11.06	11.25	11.11	10.63
SO BUILDLEN	CT4	9.82	8.72	7.35	8.72	9.82	10.63
SO BUILDLEN	CT4	11.11	11.25	11.06	10.52	9.67	8.53
SO BUILDLEN	CT4	9.67	10.52	11.06	11.25	11.11	10.63
SO BUILDLEN	CT4	9.82	8.72	7.35	8.72	9.82	10.63
SO BUILDLEN	CT4	11.11	11.25	11.06	10.52	9.67	8.53
SO XBADJ	CT4	2.47	1.74	0.97	0.16	-0.65	-1.44
SO XBADJ	CT4	-2.18	-2.86	-3.46	-5.42	-7.23	-8.81
SO XBADJ	CT4	-10.13	-11.14	-11.81	-12.12	-12.06	-11.64
SO XBADJ	CT4	-12.14	-12.27	-12.03	-11.42	-10.46	-9.19
SO XBADJ	CT4	-7.64	-5.85	-3.89	-3.29	-2.59	-1.81
SO XBADJ	CT4	-0.98	-0.12	0.75	1.59	2.39	3.11
SO YBADJ	CT4	1.07	2.32	3.50	4.57	5.51	6.28
SO YBADJ	CT4	6.86	7.23	7.38	7.30	7.01	6.50
SO YBADJ	CT4	5.79	4.91	3.88	2.73	1.50	0.22
SO YBADJ	CT4	-1.07	-2.32	-3.50	-4.57	-5.51	-6.28
SO YBADJ	CT4	-6.86	-7.23	-7.38	-7.30	-7.01	-6.50
SO YBADJ	CT4	-5.79	-4.91	-3.88	-2.73	-1.50	-0.22

SO BUILDHGT	CT5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT5	6.71	0.00	0.00	6.71	6.71	6.71
SO BUILDHGT	CT5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	CT5	6.71	0.00	0.00	6.71	6.71	6.71
SO BUILDHGT	CT5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDWID	CT5	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	CT5	10.52	0.00	0.00	9.67	10.52	11.06
SO BUILDWID	CT5	11.25	11.11	10.63	9.82	8.72	7.35
SO BUILDWID	CT5	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	CT5	10.52	0.00	0.00	9.67	10.52	11.06
SO BUILDWID	CT5	11.25	11.11	10.63	9.82	8.72	7.35

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SO BUILDLEN CT5          9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN CT5          9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN CT5         11.11   11.25   11.06   10.52    9.67    8.52
SO BUILDLEN CT5          9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN CT5          9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN CT5         11.11   11.25   11.06   10.52    9.67    8.53
SO XBADJ    CT5          3.30    2.47    1.56    0.60   -0.37   -1.34
SO XBADJ    CT5         -2.26    0.00    0.00   -5.99   -7.93   -9.63
SO XBADJ    CT5        -11.04  -12.11  -12.81  -13.12  -13.04  -12.56
SO XBADJ    CT5        -12.97  -12.99  -12.61  -11.86  -10.74   -9.29
SO XBADJ    CT5         -7.56    0.00    0.00   -2.72   -1.89   -1.00
SO XBADJ    CT5         -0.07    0.85    1.75    2.60    3.37    4.03
SO YBADJ    CT5          1.63    3.02    4.32    5.48    6.48    7.28
SO YBADJ    CT5          7.86    0.00    0.00    8.14    7.73    7.09
SO YBADJ    CT5          6.23    5.18    3.98    2.65    1.25   -0.20
SO YBADJ    CT5         -1.63   -3.02   -4.32   -5.48   -6.48   -7.28
SO YBADJ    CT5         -7.86    0.00    0.00   -8.14   -7.73   -7.09
SO YBADJ    CT5         -6.23   -5.18   -3.98   -2.65   -1.25    0.20


SO BUILDHGT HEATER1      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER1      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER1      6.71    6.71    0.00    0.00   14.33   14.33
SO BUILDHGT HEATER1      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER1      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER1      6.71    6.71    0.00    0.00    0.00    0.00
SO BUILDWID HEATER1      8.72    9.82   10.63   11.11   11.26   11.06
SO BUILDWID HEATER1     10.53    9.67    8.53    9.67   10.53   11.06
SO BUILDWID HEATER1     11.26   11.11    0.00    0.00   14.73   13.36
SO BUILDWID HEATER1      8.72    9.82   10.63   11.11   11.26   11.06
SO BUILDWID HEATER1     10.53    9.67    8.53    9.67   10.53   11.06
SO BUILDWID HEATER1     11.26   11.11    0.00    0.00    0.00    0.00
SO BUILDLEN HEATER1      9.67   10.53   11.06   11.26   11.11   10.63
SO BUILDLEN HEATER1      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER1     11.11   11.26    0.00    0.00   11.24    9.06
SO BUILDLEN HEATER1      9.67   10.53   11.06   11.26   11.11   10.63
SO BUILDLEN HEATER1      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER1     11.11   11.26    0.00    0.00    0.00    0.00
SO XBADJ    HEATER1      1.61    2.13    2.59    2.97    3.25    3.44
SO XBADJ    HEATER1      3.53    3.51    3.38    1.67   -0.10   -1.86
SO XBADJ    HEATER1     -3.56   -5.16    0.00    0.00  -80.53  -79.79
SO XBADJ    HEATER1    -11.28  -12.66  -13.65  -14.22  -14.37  -14.07
SO XBADJ    HEATER1    -13.35  -12.23  -10.73  -10.38   -9.73   -8.77
SO XBADJ    HEATER1     -7.55   -6.10    0.00    0.00    0.00    0.00
SO YBADJ    HEATER1     -6.03   -4.81   -3.46   -2.00   -0.47    1.06
SO YBADJ    HEATER1      2.57    4.00    5.30    6.45    7.39    8.12
SO YBADJ    HEATER1      8.59    8.81    0.00    0.00    8.59   -4.54
SO YBADJ    HEATER1      6.03    4.81    3.46    2.00    0.47   -1.06
SO YBADJ    HEATER1     -2.57   -4.00   -5.30   -6.45   -7.39   -8.12
SO YBADJ    HEATER1     -8.59   -8.81    0.00    0.00    0.00    0.00


SO BUILDHGT HEATER2      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER2      6.71    6.71    6.71    6.71    6.71    6.71
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SO	BUILDHGT	HEATER2	0.00	0.00	0.00	0.00	14.33	14.33
SO	BUILDHGT	HEATER2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	HEATER2	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	HEATER2	0.00	0.00	0.00	0.00	0.00	0.00
SO	BUILDWID	HEATER2	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	HEATER2	10.53	9.67	8.53	9.67	10.53	11.06
SO	BUILDWID	HEATER2	0.00	0.00	0.00	0.00	14.73	13.36
SO	BUILDWID	HEATER2	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	HEATER2	10.53	9.67	8.53	9.67	10.53	11.06
SO	BUILDWID	HEATER2	0.00	0.00	0.00	0.00	0.00	0.00
SO	BUILDLEN	HEATER2	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	HEATER2	9.82	8.72	7.35	8.72	9.82	10.63
SO	BUILDLEN	HEATER2	0.00	0.00	0.00	0.00	11.24	9.06
SO	BUILDLEN	HEATER2	9.67	10.53	11.06	11.26	11.11	10.63
SO	BUILDLEN	HEATER2	9.82	8.72	7.35	8.72	9.82	10.63
SO	BUILDLEN	HEATER2	0.00	0.00	0.00	0.00	0.00	0.00
SO	XBADJ	HEATER2	2.18	2.68	3.11	3.44	3.66	3.78
SO	XBADJ	HEATER2	3.78	3.66	3.43	1.62	-0.24	-2.09
SO	XBADJ	HEATER2	0.00	0.00	0.00	0.00	-80.55	-79.86
SO	XBADJ	HEATER2	-11.85	-13.21	-14.17	-14.69	-14.77	-14.40
SO	XBADJ	HEATER2	-13.60	-12.38	-10.78	-10.34	-9.58	-8.54
SO	XBADJ	HEATER2	0.00	0.00	0.00	0.00	0.00	0.00
SO	YBADJ	HEATER2	-5.98	-4.67	-3.22	-1.67	-0.07	1.53
SO	YBADJ	HEATER2	3.08	4.54	5.87	7.01	7.95	8.64
SO	YBADJ	HEATER2	0.00	0.00	0.00	0.00	8.88	-4.27
SO	YBADJ	HEATER2	5.98	4.67	3.22	1.67	0.07	-1.53
SO	YBADJ	HEATER2	-3.08	-4.54	-5.87	-7.01	-7.95	-8.64
SO	YBADJ	HEATER2	0.00	0.00	0.00	0.00	0.00	0.00

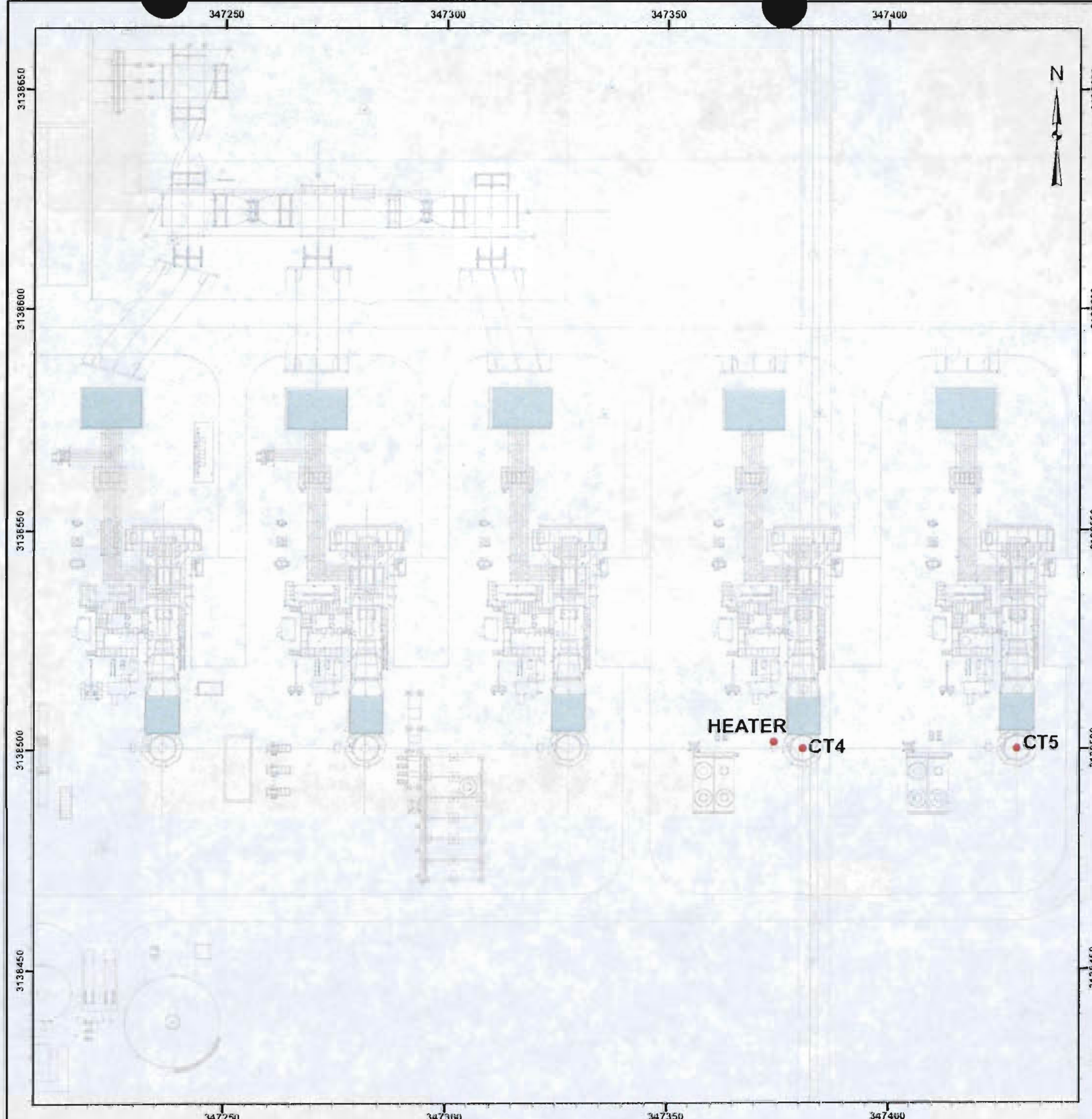
SO	BUILDHGT	HEATER3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	HEATER3	6.71	6.71	6.71	6.71	6.71	0.00
SO	BUILDHGT	HEATER3	0.00	0.00	0.00	0.00	0.00	6.71
SO	BUILDHGT	HEATER3	6.71	6.71	6.71	6.71	6.71	6.71
SO	BUILDHGT	HEATER3	6.71	6.71	6.71	6.71	6.71	0.00
SO	BUILDHGT	HEATER3	0.00	0.00	0.00	0.00	0.00	6.71
SO	BUILDWID	HEATER3	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	HEATER3	10.52	9.67	8.53	9.67	10.52	0.00
SO	BUILDWID	HEATER3	0.00	0.00	0.00	0.00	0.00	7.35
SO	BUILDWID	HEATER3	8.72	9.82	10.63	11.11	11.26	11.06
SO	BUILDWID	HEATER3	10.52	9.67	8.53	9.67	10.52	0.00
SO	BUILDWID	HEATER3	0.00	0.00	0.00	0.00	0.00	7.35
SO	BUILDLEN	HEATER3	9.67	10.52	11.06	11.26	11.11	10.63
SO	BUILDLEN	HEATER3	9.82	8.72	7.35	8.72	9.82	0.00
SO	BUILDLEN	HEATER3	0.00	0.00	0.00	0.00	0.00	8.52
SO	BUILDLEN	HEATER3	9.67	10.52	11.06	11.26	11.11	10.63
SO	BUILDLEN	HEATER3	9.82	8.72	7.35	8.72	9.82	0.00
SO	BUILDLEN	HEATER3	0.00	0.00	0.00	0.00	0.00	8.53
SO	XBADJ	HEATER3	2.82	3.23	3.54	3.74	3.82	3.79
SO	XBADJ	HEATER3	3.65	3.39	3.04	1.10	-0.86	0.00
SO	XBADJ	HEATER3	0.00	0.00	0.00	0.00	0.00	-10.86
SO	XBADJ	HEATER3	-12.49	-13.75	-14.59	-14.99	-14.93	-14.42
SO	XBADJ	HEATER3	-13.47	-12.11	-10.39	-9.82	-8.96	0.00
SO	XBADJ	HEATER3	0.00	0.00	0.00	0.00	0.00	2.33

SO YBADJ	HEATER3	-5.46	-4.05	-2.52	-0.90	0.74	2.35
SO YBADJ	HEATER3	3.90	5.33	6.59	7.66	8.49	0.00
SO YBADJ	HEATER3	0.00	0.00	0.00	0.00	0.00	6.71
SO YBADJ	HEATER3	5.46	4.05	2.52	0.90	-0.74	-2.35
SO YBADJ	HEATER3	-3.90	-5.33	-6.59	-7.66	-8.49	0.00
SO YBADJ	HEATER3	0.00	0.00	0.00	0.00	0.00	-6.71

SO BUILDHGT	HEATER4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER4	6.71	0.00	0.00	0.00	14.33	14.33
SO BUILDHGT	HEATER4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER4	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER4	6.71	0.00	0.00	0.00	6.71	6.71
SO BUILDWID	HEATER4	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	HEATER4	10.52	9.67	8.53	9.67	10.52	11.06
SO BUILDWID	HEATER4	11.25	0.00	0.00	0.00	14.73	13.36
SO BUILDWID	HEATER4	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	HEATER4	10.52	9.67	8.53	9.67	10.52	11.06
SO BUILDWID	HEATER4	11.25	0.00	0.00	0.00	8.72	7.35
SO BUILDLEN	HEATER4	9.67	10.52	11.06	11.25	11.11	10.63
SO BUILDLEN	HEATER4	9.82	8.72	7.35	8.72	9.82	10.63
SO BUILDLEN	HEATER4	11.11	0.00	0.00	0.00	11.24	9.06
SO BUILDLEN	HEATER4	9.67	10.52	11.06	11.25	11.11	10.63
SO BUILDLEN	HEATER4	9.82	8.72	7.35	8.72	9.82	10.63
SO BUILDLEN	HEATER4	11.11	0.00	0.00	0.00	9.67	8.53
SO XBADJ	HEATER4	2.18	2.62	2.98	3.25	3.43	3.50
SO XBADJ	HEATER4	3.46	3.32	3.07	1.26	-0.60	-2.44
SO XBADJ	HEATER4	-4.20	0.00	0.00	0.00	-80.88	-80.15
SO XBADJ	HEATER4	-11.85	-13.14	-14.04	-14.51	-14.54	-14.12
SO XBADJ	HEATER4	-13.28	-12.03	-10.42	-9.97	-9.22	-8.19
SO XBADJ	HEATER4	-6.91	0.00	0.00	0.00	-0.17	1.67
SO YBADJ	HEATER4	-5.61	-4.31	-2.88	-1.36	0.21	1.76
SO YBADJ	HEATER4	3.27	4.67	5.93	7.01	7.88	8.51
SO YBADJ	HEATER4	8.88	0.00	0.00	0.00	8.66	-4.54
SO YBADJ	HEATER4	5.61	4.31	2.88	1.36	-0.21	-1.76
SO YBADJ	HEATER4	-3.27	-4.67	-5.93	-7.01	-7.88	-8.51
SO YBADJ	HEATER4	-8.88	0.00	0.00	0.00	-7.67	-6.75

SO BUILDHGT	HEATER5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER5	6.71	6.71	6.71	6.71	6.71	0.00
SO BUILDHGT	HEATER5	0.00	0.00	0.00	6.71	6.71	6.71
SO BUILDHGT	HEATER5	6.71	6.71	6.71	6.71	6.71	6.71
SO BUILDHGT	HEATER5	6.71	6.71	6.71	6.71	6.71	0.00
SO BUILDHGT	HEATER5	0.00	0.00	0.00	6.71	6.71	6.71
SO BUILDWID	HEATER5	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	HEATER5	10.52	9.67	8.53	9.67	10.52	0.00
SO BUILDWID	HEATER5	0.00	0.00	0.00	9.82	8.72	7.35
SO BUILDWID	HEATER5	8.72	9.82	10.63	11.11	11.25	11.06
SO BUILDWID	HEATER5	10.52	9.67	8.53	9.67	10.52	0.00
SO BUILDWID	HEATER5	0.00	0.00	0.00	9.82	8.72	7.35
SO BUILDLEN	HEATER5	9.67	10.52	11.06	11.25	11.11	10.63
SO BUILDLEN	HEATER5	9.82	8.72	7.35	8.72	9.82	0.00

SO	BUILDLEN	HEATER5	0.00	0.00	0.00	10.52	9.67	8.52
SO	BUILDLEN	HEATER5	9.67	10.52	11.06	11.25	11.11	10.63
SO	BUILDLEN	HEATER5	9.82	8.72	7.35	8.72	9.82	0.00
SO	BUILDLEN	HEATER5	0.00	0.00	0.00	10.52	9.67	8.53
SO	XBADJ	HEATER5	2.83	3.17	3.41	3.54	3.57	3.49
SO	XBADJ	HEATER5	3.30	3.02	2.64	0.70	-1.26	0.00
SO	XBADJ	HEATER5	0.00	0.00	0.00	-9.37	-10.31	-10.93
SO	XBADJ	HEATER5	-12.50	-13.69	-14.46	-14.80	-14.68	-14.12
SO	XBADJ	HEATER5	-13.13	-11.74	-9.99	-9.42	-8.56	0.00
SO	XBADJ	HEATER5	0.00	0.00	0.00	-1.15	0.64	2.41
SO	YBADJ	HEATER5	-5.06	-3.65	-2.13	-0.55	1.05	2.62
SO	YBADJ	HEATER5	4.11	5.47	6.67	7.67	8.43	0.00
SO	YBADJ	HEATER5	0.00	0.00	0.00	8.22	7.38	6.31
SO	YBADJ	HEATER5	5.06	3.65	2.13	0.55	-1.05	-2.62
SO	YBADJ	HEATER5	-4.11	-5.47	-6.67	-7.67	-8.43	0.00
SO	YBADJ	HEATER5	0.00	0.00	0.00	-8.22	-7.38	-6.31



LEGEND

- Souce Locations
- Buildings Used in Downwash
- Fence Line

PROPERTY BOUNDARY

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

30 0 30 Meters

PROJECT

GE Energy - Shady Hills

TITLE

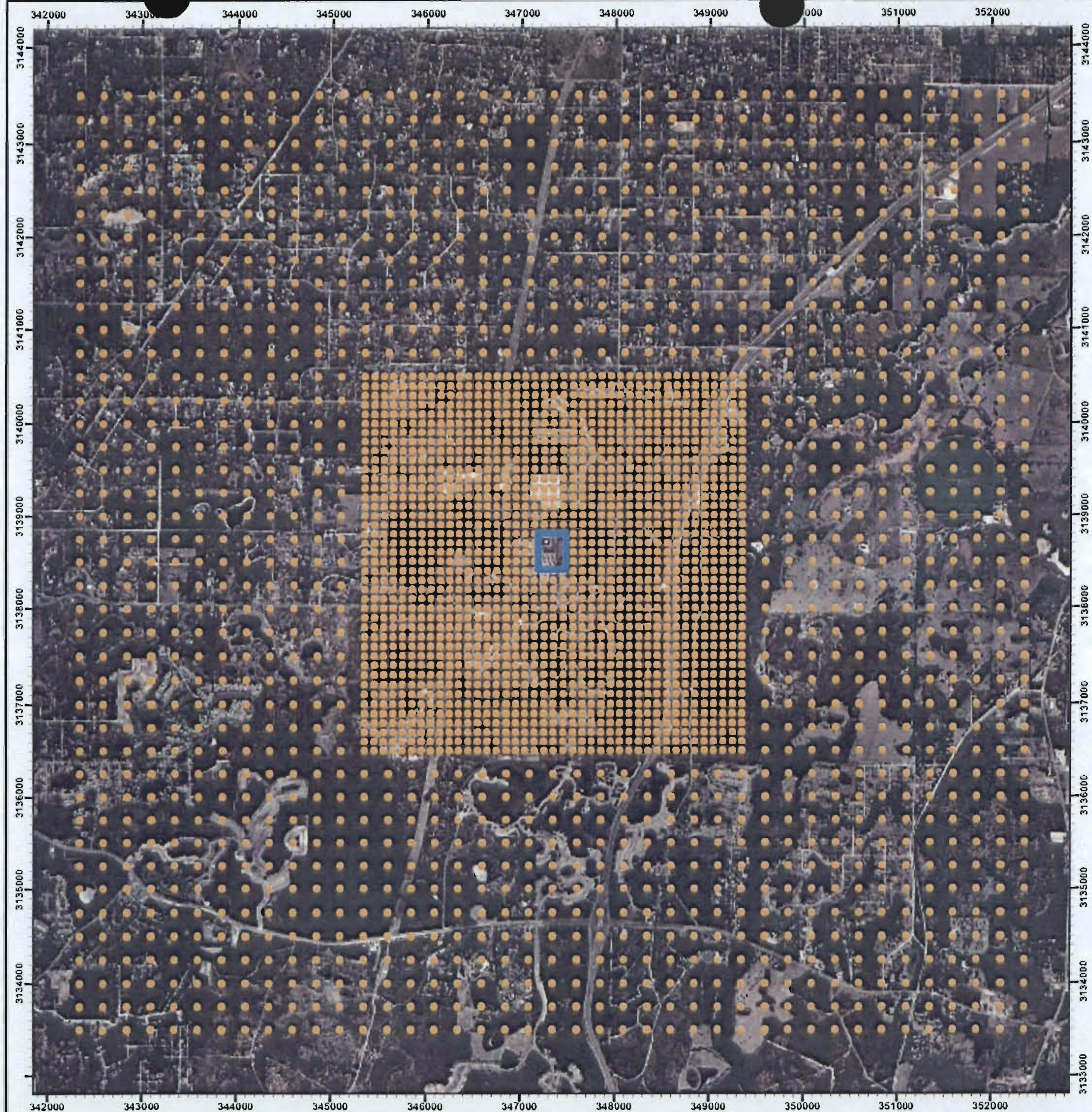
Source and Building Locations

Golder Associates
Gainesville, Florida

PROJECT No.	083-89590	
DESIGN	AB	28 Mar. 2008
GIS	AB	28 Mar. 2008
CHECK	SM	28 Mar. 2008
REVIEW	SM	28 Mar. 2008

SCALE AS SHOWN | REV. 0

FIGURE 1



LEGEND

- Fence Line Receptors
- Receptor Grid

REFERENCE

Projection: Transverse Mercator Datum: NAD 27 Coordinate System: UTM Zone 17

1,000 0 1,000 Meters

PROJECT

GE Energy - Shady Hills

TITLE

Receptor Grid

Golder Associates
Gainesville, Florida

PROJECT No.	083-89507		SCALE AS SHOWN	REV. 0
DESIGN	AB	28 Mar. 2008	**FIGURE 2**	
GIS	AB	28 Mar. 2008		
CHECK	SM	28 Mar. 2008		
REVIEW	SM	28 Mar. 2008		

APPENDIX E

SAMPLE AERMOD INPUT AND IMPACT SUMMARIES FOR:

CT LOAD ANALYSIS - NATURAL GAS FIRING
PM10 SIGNIFICANT IMPACT ANALYSIS
NO2 SIGNIFICANT IMPACT ANALYSIS
CO SIGNIFICANT IMPACT ANALYSIS

```
CO STARTING
CO TITLEONE 2001 SHADY HILLS 2 SIMPLE CYCLE CTS            5/6/08
CO TITLETWO NATURAL GAS, 10G/S GENERIC EM, 3 LOADS AND 3 TEMPERATURES
CO MODELOPT DFAULT CONC   NOWARN
CO AVERTIME  PERIOD 24 8 3 1
CO POLLUTID GEN
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** -----------------------
**  A -  CT 4
**  B -  CT 5
** Source Location Cards:
**          SRCID SRCTYP          XS         YS          ZS
**   UTM                          (m)        (m)         (m)
SO LOCATION  BASE20A  POINT  347380.860 3138500.455 15.99
SO LOCATION  BASE20B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  BASE59A  POINT  347380.860 3138500.455 15.99
SO LOCATION  BASE59B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  BASE95A  POINT  347380.860 3138500.455 15.99
SO LOCATION  BASE95B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD7520A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD7520B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD7559A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD7559B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD7595A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD7595B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD5020A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD5020B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD5059A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD5059B  POINT  347429.354 3138500.417 15.34
**
SO LOCATION  LD5095A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD5095B  POINT  347429.354 3138500.417 15.34
**
** Source Parameter Cards:
** POINT:   SRCID          QS        HS         TS        VS         DS
**                       (g/s)       (m)        (K)      (m/s)       (m)
SO SRCPARAM    BASE20A    5.0       22.9       852.0     34.42      6.71
SO SRCPARAM    BASE20B    5.0       22.9       852.0     34.42      6.71
**
SO SRCPARAM    BASE59A    5.0       22.9       873.7     32.91      6.71
SO SRCPARAM    BASE59B    5.0       22.9       873.7     32.91      6.71
**
SO SRCPARAM    BASE95A    5.0       22.9       896.5     31.00      6.71
SO SRCPARAM    BASE95B    5.0       22.9       896.5     31.00      6.71
**
SO SRCPARAM    LD7520A    5.0       22.9       922.0     28.06      6.71
SO SRCPARAM    LD7520B    5.0       22.9       922.0     28.06      6.71
**
SO SRCPARAM    LD7559A    5.0       22.9       899.3     27.27      6.71
SO SRCPARAM    LD7559B    5.0       22.9       899.3     27.27      6.71
**
SO SRCPARAM    LD7595A    5.0       22.9       916.5     26.26      6.71
SO SRCPARAM    LD7595B    5.0       22.9       916.5     26.26      6.71
**
SO SRCPARAM    LD5020A    5.0       22.9       922.0     23.68      6.71
SO SRCPARAM    LD5020B    5.0       22.9       922.0     23.68      6.71
**
SO SRCPARAM    LD5059A    5.0       22.9       922.0     23.11      6.71
SO SRCPARAM    LD5059B    5.0       22.9       922.0     23.11      6.71
**
SO SRCPARAM    LD5095A    5.0       22.9       922.0     22.23      6.71
SO SRCPARAM    LD5095B    5.0       22.9       922.0     22.23      6.71
**
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDHGT BASE20A-BASE95A    6.71      6.71      6.71      6.71      6.71      6.71
SO BUILDWID BASE20A-BASE95A    8.72      9.82     10.63     11.11     11.25     11.06
SO BUILDWID BASE20A-BASE95A   10.52      9.67      8.53      9.67     10.52     11.06
```

```
SO BUILDWID  BASE20A-BASE95A   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDWID  BASE20A-BASE95A    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID  BASE20A-BASE95A   10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID  BASE20A-BASE95A   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDLEN  BASE20A-BASE95A    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  BASE20A-BASE95A    9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN  BASE20A-BASE95A   11.11   11.25   11.06   10.52    9.67    8.53
SO BUILDLEN  BASE20A-BASE95A    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  BASE20A-BASE95A    9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN  BASE20A-BASE95A   11.11   11.25   11.06   10.52    9.67    8.53
SO XBADJ     BASE20A-BASE95A    2.47    1.74    0.97    0.16   -0.65   -1.44
SO XBADJ     BASE20A-BASE95A   -2.18   -2.86   -3.46   -5.42   -7.23   -8.81
SO XBADJ     BASE20A-BASE95A  -10.13  -11.14  -11.81  -12.12  -12.06  -11.64
SO XBADJ     BASE20A-BASE95A  -12.14  -12.27  -12.03  -11.42  -10.46   -9.19
SO XBADJ     BASE20A-BASE95A   -7.64   -5.85   -3.89   -3.29   -2.59   -1.81
SO XBADJ     BASE20A-BASE95A   -0.98   -0.12    0.75    1.59    2.39    3.11
SO YBADJ     BASE20A-BASE95A    1.07    2.32    3.50    4.57    5.51    6.28
SO YBADJ     BASE20A-BASE95A    6.86    7.23    7.38    7.30    7.01    6.50
SO YBADJ     BASE20A-BASE95A    5.79    4.91    3.88    2.73    1.50    0.22
SO YBADJ     BASE20A-BASE95A   -1.07   -2.32   -3.50   -4.57   -5.51   -6.28
SO YBADJ     BASE20A-BASE95A   -6.86   -7.23   -7.38   -7.30   -7.01   -6.50
SO YBADJ     BASE20A-BASE95A   -5.79   -4.91   -3.88   -2.73   -1.50   -0.22
**
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  LD5020A-LD7595A    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDWID  LD5020A-LD7595A    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID  LD5020A-LD7595A   10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID  LD5020A-LD7595A   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDWID  LD5020A-LD7595A    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID  LD5020A-LD7595A   10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID  LD5020A-LD7595A   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDLEN  LD5020A-LD7595A    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  LD5020A-LD7595A    9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN  LD5020A-LD7595A   11.11   11.25   11.06   10.52    9.67    8.53
SO BUILDLEN  LD5020A-LD7595A    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  LD5020A-LD7595A    9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN  LD5020A-LD7595A   11.11   11.25   11.06   10.52    9.67    8.53
SO XBADJ     LD5020A-LD7595A    2.47    1.74    0.97    0.16   -0.65   -1.44
SO XBADJ     LD5020A-LD7595A   -2.18   -2.86   -3.46   -5.42   -7.23   -8.81
SO XBADJ     LD5020A-LD7595A  -10.13  -11.14  -11.81  -12.12  -12.06  -11.64
SO XBADJ     LD5020A-LD7595A  -12.14  -12.27  -12.03  -11.42  -10.46   -9.19
SO XBADJ     LD5020A-LD7595A   -7.64   -5.85   -3.89   -3.29   -2.59   -1.81
SO XBADJ     LD5020A-LD7595A   -0.98   -0.12    0.75    1.59    2.39    3.11
SO YBADJ     LD5020A-LD7595A    1.07    2.32    3.50    4.57    5.51    6.28
SO YBADJ     LD5020A-LD7595A    6.86    7.23    7.38    7.30    7.01    6.50
SO YBADJ     LD5020A-LD7595A    5.79    4.91    3.88    2.73    1.50    0.22
SO YBADJ     LD5020A-LD7595A   -1.07   -2.32   -3.50   -4.57   -5.51   -6.28
SO YBADJ     LD5020A-LD7595A   -6.86   -7.23   -7.38   -7.30   -7.01   -6.50
SO YBADJ     LD5020A-LD7595A   -5.79   -4.91   -3.88   -2.73   -1.50   -0.22
**
SO BUILDHGT  BASE20B-BASE95B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  BASE20B-BASE95B    6.71    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT  BASE20B-BASE95B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  BASE20B-BASE95B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT  BASE20B-BASE95B    6.71    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT  BASE20B-BASE95B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDWID  BASE20B-BASE95B    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID  BASE20B-BASE95B   10.52    0.00    0.00    9.67   10.52   11.06
SO BUILDWID  BASE20B-BASE95B   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDWID  BASE20B-BASE95B    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID  BASE20B-BASE95B   10.52    0.00    0.00    9.67   10.52   11.06
SO BUILDWID  BASE20B-BASE95B   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDLEN  BASE20B-BASE95B    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  BASE20B-BASE95B    9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN  BASE20B-BASE95B   11.11   11.25   11.06   10.52    9.67    8.52
SO BUILDLEN  BASE20B-BASE95B    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN  BASE20B-BASE95B    9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN  BASE20B-BASE95B   11.11   11.25   11.06   10.52    9.67    8.53
SO XBADJ     BASE20B-BASE95B    3.30    2.47    1.56    0.60   -0.37   -1.34
SO XBADJ     BASE20B-BASE95B   -2.26    0.00    0.00   -5.99   -7.93   -9.63
SO XBADJ     BASE20B-BASE95B  -11.04  -12.11  -12.81  -13.12  -13.04  -12.56
SO XBADJ     BASE20B-BASE95B  -12.97  -12.99  -12.61  -11.86  -10.74   -9.29
SO XBADJ     BASE20B-BASE95B   -7.56    0.00    0.00   -2.72   -1.89   -1.00
SO XBADJ     BASE20B-BASE95B   -0.07    0.85    1.75    2.60    3.37    4.03
SO YBADJ     BASE20B-BASE95B    1.63    3.02    4.32    5.48    6.48    7.28
SO YBADJ     BASE20B-BASE95B    7.86    0.00    0.00    8.14    7.73    7.09
SO YBADJ     BASE20B-BASE95B    6.23    5.18    3.98    2.65    1.25   -0.20
SO YBADJ     BASE20B-BASE95B   -1.63   -3.02   -4.32   -5.48   -6.48   -7.28
SO YBADJ     BASE20B-BASE95B   -7.86    0.00    0.00   -8.14   -7.73   -7.09
```

```
SO YBADJ    BASE20B-BASE95B   -6.23   -5.18   -3.98   -2.65   -1.25    0.20

SO BUILDHGT LD5020B-LD7595B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5020B-LD7595B    6.71    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT LD5020B-LD7595B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5020B-LD7595B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT LD5020B-LD7595B    6.71    0.00    0.00    6.71    6.71    6.71
SO BUILDHGT LD5020B-LD7595B    6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDWID LD5020B-LD7595B    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID LD5020B-LD7595B   10.52    0.00    0.00    9.67   10.52   11.06
SO BUILDWID LD5020B-LD7595B   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDWID LD5020B-LD7595B    8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID LD5020B-LD7595B   10.52    0.00    0.00    9.67   10.52   11.06
SO BUILDWID LD5020B-LD7595B   11.25   11.11   10.63    9.82    8.72    7.35
SO BUILDLEN LD5020B-LD7595B    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN LD5020B-LD7595B    9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN LD5020B-LD7595B   11.11   11.25   11.06   10.52    9.67    8.52
SO BUILDLEN LD5020B-LD7595B    9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN LD5020B-LD7595B    9.82    0.00    0.00    8.72    9.82   10.63
SO BUILDLEN LD5020B-LD7595B   11.11   11.25   11.06   10.52    9.67    8.53
SO XBADJ    LD5020B-LD7595B    3.30    2.47    1.56    0.60   -0.37   -1.34
SO XBADJ    LD5020B-LD7595B   -2.26    0.00    0.00   -5.99   -7.93   -9.63
SO XBADJ    LD5020B-LD7595B  -11.04  -12.11  -12.81  -13.12  -13.04  -12.56
SO XBADJ    LD5020B-LD7595B  -12.97  -12.99  -12.61  -11.86  -10.74   -9.29
SO XBADJ    LD5020B-LD7595B   -7.56    0.00    0.00   -2.72   -1.89   -1.00
SO XBADJ    LD5020B-LD7595B   -0.07    0.85    1.75    2.60    3.37    4.03
SO YBADJ    LD5020B-LD7595B    1.63    3.02    4.32    5.48    6.48    7.28
SO YBADJ    LD5020B-LD7595B    7.86    0.00    0.00    8.14    7.73    7.09
SO YBADJ    LD5020B-LD7595B    6.23    5.18    3.98    2.65    1.25   -0.20
SO YBADJ    LD5020B-LD7595B   -1.63   -3.02   -4.32   -5.48   -6.48   -7.28
SO YBADJ    LD5020B-LD7595B   -7.86    0.00    0.00   -8.14   -7.73   -7.09
SO YBADJ    LD5020B-LD7595B   -6.23   -5.18   -3.98   -2.65   -1.25    0.20
**
SO EMISUNIT    .100000E+07 (GRAMS/SEC)         (MICROGRAMS/CUBIC-METER)
SO SRCGROUP BASE20 BASE20A BASE20B
SO SRCGROUP BASE59 BASE59A BASE59B
SO SRCGROUP BASE95 BASE95A BASE95B
SO SRCGROUP LD7520 LD7520A LD7520B
SO SRCGROUP LD7559 LD7559A LD7559B
SO SRCGROUP LD7595 LD7595A LD7595B
SO SRCGROUP LD5020 LD5020A LD5020B
SO SRCGROUP LD5059 LD5059A LD5059B
SO SRCGROUP LD5095 LD5095A LD5095B
**
SO FINISHED

RE STARTING
   INCLUDED sh0308.rou
RE FINISHED
**
****************************************
** AERMOD Meteorology Pathway
****************************************
**
**
ME STARTING
   SURFFILE C:\amodmet\TPATPA01.SFC
   PROFFILE C:\amodmet\TPATPA01.PFL
   SURFDATA 12842 2001 TAMPA/INT'L_ARPT
   UAIRDATA 12842 2001 TAMPA/INT'L_ARPT
   PROFBASE 19 FEET
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

AERBOB RELEASE 020304

AERMOD OUTPUT FILE NUMBER 1 :gengas.o01
AERMOD OUTPUT FILE NUMBER 2 :gengas.o02
AERMOD OUTPUT FILE NUMBER 3 :gengas.o03
AERMOD OUTPUT FILE NUMBER 4 :gengas.o04
AERMOD OUTPUT FILE NUMBER 5 :gengas.o05
First title for last output file is: 2001 SHADY HILLS 2 SIMPLE CYCLE CTS 5/6/08
Second title for last output file is: NATURAL GAS, 10G/S GENERIC EM, 3 LOADS AND 3 TEMPERATURES

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	BASE20				
Annual					
	2001	0.05952	347850.	3138500.	01123124
	2002	0.04066	347750.	3138600.	02123124
	2003	0.05467	347850.	3138500.	03123124
	2004	0.04925	347750.	3138600.	04123124
	2005	0.08900	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.56862	347650.	3139200.	01072324
	2002	0.38071	346950.	3138900.	02040824
	2003	0.41752	347950.	3138500.	03053024
	2004	0.72074	347850.	3139900.	04090624
	2005	0.68349	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.41582	347650.	3139300.	01072316
	2002	1.03094	346950.	3138900.	02040816
	2003	1.04779	348050.	3138400.	03060116
	2004	1.76290	347550.	3137500.	04090516
	2005	1.79158	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.05553	348050.	3138100.	01030515
	2002	1.52844	348150.	3137900.	02111712
	2003	1.53994	348150.	3138200.	03041015
	2004	2.38042	347950.	3139900.	04090606
	2005	2.20353	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	2.51173	348150.	3138000.	01030514
	2002	2.37751	348050.	3137800.	02022713
	2003	2.69378	345100.	3135000.	03011310
	2004	4.22436	347950.	3139700.	04090606
	2005	2.90207	344100.	3134750.	05121009
SOURCE GROUP ID:	BASE59				
Annual					
	2001	0.06213	347850.	3138500.	01123124
	2002	0.04248	347750.	3138600.	02123124
	2003	0.05703	347850.	3138500.	03123124
	2004	0.05139	347750.	3138600.	04123124
	2005	0.09248	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.59327	347650.	3139200.	01072324
	2002	0.39938	346950.	3138900.	02040824
	2003	0.43435	348050.	3138400.	03060124
	2004	0.76201	347850.	3139800.	04090624
	2005	0.71292	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.47225	347650.	3139300.	01072316
	2002	1.08218	346950.	3138900.	02040816
	2003	1.09334	348050.	3138400.	03060116
	2004	1.82456	347550.	3137500.	04090516
	2005	1.86880	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.13695	348050.	3138100.	01030515
	2002	1.59122	348150.	3137900.	02111712
	2003	1.61106	348150.	3138200.	03041015
	2004	2.50335	347950.	3139800.	04090606
	2005	2.29390	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	2.59035	348150.	3138000.	01030514
	2002	2.45624	348050.	3137800.	02022713
	2003	2.77603	345100.	3135000.	03011310
	2004	4.39709	347950.	3139700.	04090606
	2005	2.98432	344100.	3134750.	05121009
SOURCE GROUP ID:	BASE95				
Annual					
	2001	0.06609	347850.	3138500.	01123124
	2002	0.04525	347750.	3138600.	02123124
	2003	0.06061	347850.	3138500.	03123124
	2004	0.05466	347750.	3138600.	04123124
	2005	0.09771	347850.	3138500.	05123124

HIGH 24-Hour					
	2001	0.63022	347650.	3139200.	01072324
	2002	0.42772	346950.	3138900.	02040824
	2003	0.46178	348050.	3138400.	03060124
	2004	0.82196	347850.	3139800.	04090624
	2005	0.75614	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.55654	347650.	3139300.	01072316
	2002	1.15990	346950.	3138900.	02040816
	2003	1.16202	348050.	3138400.	03060116
	2004	1.91539	347550.	3137500.	04090516
	2005	1.98190	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.25781	348050.	3138100.	01030515
	2002	1.68496	348150.	3137900.	02111712
	2003	1.71633	348150.	3138200.	03041015
	2004	2.68981	347950.	3139800.	04090606
	2005	2.42761	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	2.70619	348150.	3138000.	01030514
	2002	2.57217	348050.	3137800.	02022713
	2003	2.90264	345350.	3135250.	03011310
	2004	4.73223	347850.	3139500.	04090606
	2005	3.11187	344100.	3134750.	05121009
SOURCE GROUP ID:	LD7520				
Annual					
	2001	0.07382	347850.	3138500.	01123124
	2002	0.05090	347850.	3138600.	02123124
	2003	0.06761	347850.	3138500.	03123124
	2004	0.06113	347850.	3138600.	04123124
	2005	0.10775	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.70150	347650.	3139200.	01072324
	2002	0.48326	346950.	3138900.	02040824
	2003	0.51577	347950.	3138400.	03060124
	2004	0.93706	347850.	3139800.	04090624
	2005	0.83568	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.72298	347650.	3139200.	01072316
	2002	1.31210	346950.	3138900.	02040816
	2003	1.29472	348050.	3138400.	03060116
	2004	2.09464	347550.	3137500.	04090516
	2005	2.18957	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.48740	348050.	3138100.	01030515
	2002	1.86559	348050.	3138000.	02111712
	2003	1.91112	348150.	3138200.	03041015
	2004	3.05158	347850.	3139600.	04090606
	2005	2.67154	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	2.94625	348050.	3138100.	01030613
	2002	2.78985	348050.	3137800.	02022713
	2003	3.14576	345350.	3135250.	03011310
	2004	5.36282	347850.	3139500.	04090606
	2005	3.36653	344350.	3135000.	05121009
SOURCE GROUP ID:	LD7559				
Annual					
	2001	0.07756	347850.	3138500.	01123124
	2002	0.05367	347850.	3138600.	02123124
	2003	0.07100	347850.	3138500.	03123124
	2004	0.06436	347850.	3138600.	04123124
	2005	0.11252	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.73481	347650.	3139200.	01072324
	2002	0.50997	346950.	3138900.	02040824
	2003	0.54166	347950.	3138400.	03060124
	2004	0.99391	347750.	3139600.	04090624
	2005	0.87093	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.80141	347650.	3139200.	01072316
	2002	1.38523	346950.	3138900.	02040816
	2003	1.35839	348050.	3138400.	03060116
	2004	2.18552	347550.	3137600.	04090516
	2005	2.28118	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.59270	348050.	3138100.	01030515
	2002	1.95422	348050.	3138000.	02111712
	2003	1.99794	348150.	3138200.	03041015
	2004	3.28447	347850.	3139600.	04090606
	2005	2.78375	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	3.05957	348050.	3138100.	01030613
	2002	2.88795	348050.	3137800.	02022713

	2003	3.27514	345600.	3135750.	03011310
	2004	5.67626	347850.	3139500.	04090606
	2005	3.48600	344600.	3135250.	05121009
SOURCE GROUP ID:	LD7595				
Annual					
	2001	0.08046	347850.	3138500.	01123124
	2002	0.05582	347850.	3138600.	02123124
	2003	0.07363	347850.	3138500.	03123124
	2004	0.06687	347850.	3138600.	04123124
	2005	0.11621	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.76122	347650.	3139200.	01072324
	2002	0.53103	346950.	3138900.	02040824
	2003	0.56181	347950.	3138400.	03060124
	2004	1.04796	347750.	3139600.	04090624
	2005	0.89883	348050.	3138300.	05032824
HIGH 8-Hour					
	2001	1.86385	347650.	3139200.	01072316
	2002	1.44293	346950.	3138900.	02040816
	2003	1.40726	348050.	3138400.	03060116
	2004	2.27932	347550.	3137600.	04090516
	2005	2.35337	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.68000	347950.	3138100.	01030615
	2002	2.02656	348050.	3138000.	02111712
	2003	2.06727	348150.	3138200.	03041015
	2004	3.46907	347850.	3139600.	04090606
	2005	2.86933	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	3.15272	348050.	3138100.	01030613
	2002	2.97093	347950.	3137900.	02022713
	2003	3.38493	345600.	3135750.	03011310
	2004	6.00615	347850.	3139500.	04090606
	2005	3.58449	344600.	3135500.	05121009
SOURCE GROUP ID:	LD5020				
Annual					
	2001	0.09115	347850.	3138500.	01123124
	2002	0.06385	347850.	3138600.	02123124
	2003	0.08331	347850.	3138500.	03123124
	2004	0.07624	347850.	3138600.	04123124
	2005	0.12955	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.85558	347650.	3139200.	01072324
	2002	0.60840	346950.	3138900.	02040824
	2003	0.63537	347950.	3138400.	03060124
	2004	1.25015	347750.	3139500.	04090624
	2005	1.00178	348150.	3138300.	05032824
HIGH 8-Hour					
	2001	2.08617	347650.	3139200.	01072316
	2002	1.65472	346950.	3138900.	02040816
	2003	1.62202	347850.	3138000.	03121716
	2004	2.62745	347550.	3137600.	04090516
	2005	2.60031	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	2.99196	347950.	3138100.	01030615
	2002	2.28499	348050.	3138000.	02111712
	2003	2.35804	348050.	3138700.	03030915
	2004	4.13118	347850.	3139600.	04090606
	2005	3.17185	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	3.47693	348050.	3138100.	01030613
	2002	3.27193	347950.	3137900.	02022713
	2003	3.76331	345850.	3136000.	03011310
	2004	7.36946	347750.	3139300.	04090606
	2005	3.96180	348150.	3138300.	05032813
SOURCE GROUP ID:	LD5059				
Annual					
	2001	0.09391	347850.	3138500.	01123124
	2002	0.06594	347850.	3138600.	02123124
	2003	0.08581	347850.	3138500.	03123124
	2004	0.07868	347850.	3138600.	04123124
	2005	0.13296	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.87979	347650.	3139200.	01072324
	2002	0.62847	346950.	3138900.	02040824
	2003	0.65428	347950.	3138400.	03060124
	2004	1.30898	347750.	3139500.	04090624
	2005	1.02796	348150.	3138300.	05032824
HIGH 8-Hour					
	2001	2.14295	347650.	3139200.	01072316
	2002	1.70962	346950.	3138900.	02040816
	2003	1.67883	347850.	3138000.	03121716
	2004	2.72321	347550.	3137600.	04090516

	2005	2.66207	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	3.06879	347950.	3138100.	01030615
	2002	2.35125	348050.	3138000.	02111712
	2003	2.43599	348050.	3138700.	03030915
	2004	4.30096	347850.	3139600.	04090606
	2005	3.24823	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	3.55862	348050.	3138100.	01030613
	2002	3.34782	347950.	3137900.	02022713
	2003	3.82912	345850.	3136000.	03011310
	2004	7.74872	347750.	3139300.	04090606
	2005	4.05003	348150.	3138300.	05032813
SOURCE GROUP ID:	L05095				
Annual					
	2001	0.09846	347850.	3138500.	01123124
	2002	0.06942	347850.	3138600.	02123124
	2003	0.08994	347850.	3138500.	03123124
	2004	0.08274	347850.	3138600.	04123124
	2005	0.13853	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.91956	347650.	3139200.	01072324
	2002	0.66161	346950.	3138900.	02040824
	2003	0.68536	347950.	3138400.	03060124
	2004	1.40891	347750.	3139500.	04090624
	2005	1.07000	348150.	3138300.	05032824
HIGH 8-Hour					
	2001	2.23600	347650.	3139200.	01072316
	2002	1.80025	346950.	3138900.	02040816
	2003	1.77059	347850.	3138000.	03121716
	2004	2.91966	347850.	3139600.	04090608
	2005	2.76291	348050.	3138300.	05032816
HIGH 3-Hour					
	2001	3.19248	347950.	3138100.	01030615
	2002	2.46014	348050.	3138000.	02111712
	2003	2.56437	348050.	3138700.	03030915
	2004	4.70835	347750.	3139400.	04090606
	2005	3.37273	348050.	3138300.	05032815
HIGH 1-Hour					
	2001	3.69172	348050.	3138100.	01030613
	2002	3.47150	347950.	3137900.	02022713
	2003	3.93445	345850.	3136000.	03011310
	2004	8.35437	347750.	3139300.	04090606
	2005	4.19395	348150.	3138300.	05032813

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 2001 SHADY HILLS 2 SC CTS PM10 SIG ANALYSIS          5/7/08
CO TITLETWO Fuel Oil, 50% L, 95 DEG F
CO MODELOPT DFAULT CONC   NOWARN
CO AVERTIME  PERIOD 24
CO POLLUTID PM10
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** ----------------------
**  A -  CT 4
**  B -  CT 5
** Source Location Cards:
**          SRCID SRCTYP        XS          YS          ZS
**   UTM                        (m)         (m)         (m)
SO LOCATION  LD5095A  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD5095B  POINT  347429.354 3138500.417 15.34
   LOCATION  HEATER   POINT  347374.331 3138501.899 16.13
**
** Source Parameter Cards:
** POINT:   SRCID          QS        HS        TS        VS        DS
**                        (g/s)      (m)       (K)      (m/s)      (m)
SO SRCPARAM   LD5095A   2.14       22.9      922.0     22.48      6.71
SO SRCPARAM   LD5095B   2.14       22.9      922.0     22.48      6.71
   SRCPARAM   HEATER    0.0025     9.14      533.2     16.15      0.31
**
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID LD5095A     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD5095A    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID LD5095A    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID LD5095A     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD5095A    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID LD5095A    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN LD5095A     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD5095A     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN LD5095A    11.11    11.25    11.06    10.52     9.67     8.53
SO BUILDLEN LD5095A     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD5095A     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN LD5095A    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ    LD5095A     2.47     1.74     0.97     0.16    -0.65    -1.44
SO XBADJ    LD5095A    -2.18    -2.86    -3.46    -5.42    -7.23    -8.81
SO XBADJ    LD5095A   -10.13   -11.14   -11.81   -12.12   -12.06   -11.64
SO XBADJ    LD5095A   -12.14   -12.27   -12.03   -11.42   -10.46    -9.19
SO XBADJ    LD5095A    -7.64    -5.85    -3.89    -3.29    -2.59    -1.81
SO XBADJ    LD5095A    -0.98    -0.12     0.75     1.59     2.39     3.11
SO YBADJ    LD5095A     1.07     2.32     3.50     4.57     5.51     6.28
SO YBADJ    LD5095A     6.86     7.23     7.38     7.30     7.01     6.50
SO YBADJ    LD5095A     5.79     4.91     3.88     2.73     1.50     0.22
SO YBADJ    LD5095A    -1.07    -2.32    -3.50    -4.57    -5.51    -6.28
SO YBADJ    LD5095A    -6.86    -7.23    -7.38    -7.30    -7.01    -6.50
SO YBADJ    LD5095A    -5.79    -4.91    -3.88    -2.73    -1.50    -0.22
**
SO BUILDHGT LD5095B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095B     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT LD5095B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD5095B     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT LD5095B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID LD5095B     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD5095B    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID LD5095B    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID LD5095B     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD5095B    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID LD5095B    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN LD5095B     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD5095B     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN LD5095B    11.11    11.25    11.06    10.52     9.67     8.52
SO BUILDLEN LD5095B     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD5095B     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN LD5095B    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ    LD5095B     3.30     2.47     1.56     0.60    -0.37    -1.34
SO XBADJ    LD5095B    -2.26     0.00     0.00    -5.99    -7.93    -9.63
SO XBADJ    LD5095B   -11.04   -12.11   -12.81   -13.12   -13.04   -12.56
SO XBADJ    LD5095B   -12.97   -12.99   -12.61   -11.86   -10.74    -9.29
SO XBADJ    LD5095B    -7.56     0.00     0.00    -2.72    -1.89    -1.00
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SO XBADJ    LD5095B    -0.07    0.85    1.75    2.60    3.37    4.03
SO YBADJ    LD5095B     1.63    3.02    4.32    5.48    6.48    7.28
SO YBADJ    LD5095B     7.86    0.00    0.00    8.14    7.73    7.09
SO YBADJ    LD5095B     6.23    5.18    3.98    2.65    1.25   -0.20
SO YBADJ    LD5095B    -1.63   -3.02   -4.32   -5.48   -6.48   -7.28
SO YBADJ    LD5095B    -7.86    0.00    0.00   -8.14   -7.73   -7.09
SO YBADJ    LD5095B    -6.23   -5.18   -3.98   -2.65   -1.25    0.20
**
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    0.00    0.00    0.00   14.33   14.33
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    0.00    0.00    0.00    6.71    6.71
SO BUILDWID HEATER      8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER     10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER     11.25    0.00    0.00    0.00   14.73   13.36
SO BUILDWID HEATER      8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER     10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER     11.25    0.00    0.00    0.00    8.72    7.35
SO BUILDLEN HEATER      9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER     11.11    0.00    0.00    0.00   11.24    9.06
SO BUILDLEN HEATER      9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER     11.11    0.00    0.00    0.00    9.67    8.53
SO XBADJ    HEATER      2.18    2.62    2.98    3.25    3.43    3.50
SO XBADJ    HEATER      3.46    3.32    3.07    1.26   -0.60   -2.44
SO XBADJ    HEATER     -4.20    0.00    0.00    0.00  -80.88  -80.15
SO XBADJ    HEATER    -11.85  -13.14  -14.04  -14.51  -14.54  -14.12
SO XBADJ    HEATER    -13.28  -12.03  -10.42   -9.97   -9.22   -8.19
SO XBADJ    HEATER     -6.91    0.00    0.00    0.00   -0.17    1.67
SO YBADJ    HEATER     -5.61   -4.31   -2.88   -1.36    0.21    1.76
SO YBADJ    HEATER      3.27    4.67    5.93    7.01    7.88    8.51
SO YBADJ    HEATER      8.88    0.00    0.00    0.00    8.66   -4.54
SO YBADJ    HEATER      5.61    4.31    2.88    1.36   -0.21   -1.76
SO YBADJ    HEATER     -3.27   -4.67   -5.93   -7.01   -7.88   -8.51
SO YBADJ    HEATER     -8.88    0.00    0.00    0.00   -7.67   -6.75

SO SRCGROUP ALL
**
SO FINISHED

RE STARTING
   INCLUDED sh0308.rou
RE FINISHED
**
*****************************************
** AERMOD Meteorology Pathway
*****************************************
**
**
ME STARTING
   SURFFILE C:\amodmet\TPATPA01.SFC
   PROFFILE C:\amodmet\TPATPA01.PFL
   SURFDATA 12842 2001 TAMPA/INT'L_ARPT
   UAIRDATA 12842 2001 TAMPA/INT'L_ARPT
   PROFBASE 19 FEET
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

AERBOB RELEASE 020304

[illegible]D OUTPUT FILE NUMBER 1 :pmsig.o01
[illegible]OD OUTPUT FILE NUMBER 2 :pmsig.o02
AERMOD OUTPUT FILE NUMBER 3 :pmsig.o03
AERMOD OUTPUT FILE NUMBER 4 :pmsig.o04
AERMOD OUTPUT FILE NUMBER 5 :pmsig.o05
First title for last output file is: 2001 SHADY HILLS 2 SC CTS PM10 SIG ANALYSIS 5/7/08
Second title for last output file is: Fuel Oil, 50% L, 95 DEG F

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID:	ALL				
Annual					
	2001	0.044	347750.	3138500.	01123124
	2002	0.032	347750.	3138600.	02123124
	2003	0.041	347750.	3138500.	03123124
	2004	0.039	347750.	3138600.	04123124
	2005	0.061	347850.	3138500.	05123124
HIGH 24-Hour					
	2001	0.393	347650.	3139200.	01072324
	2002	0.287	346950.	3138900.	02040824
	2003	0.300	347950.	3138400.	03060124
	2004	0.593	347750.	3139500.	04090624
	2005	0.462	348150.	3138300.	05032824

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 2001 SHADY HILLS 2 SC CTS + Heater NOx SIG ANALYSIS      3/28/08
CO TITLETWO CTs on Natural Gas 2390 hr/yr and fuel oil 1000 hr/yr
CO MODELOPT DFAULT CONC   NOWARN
CO AVERTIME  PERIOD
CO POLLUTID NOx
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** -----------------------
**  A -  CT 4
**  B -  CT 5
** Source Location Cards:
**          SRCID SRCTYP        XS          YS          ZS
**   UTM                        (m)         (m)         (m)
SO LOCATION  LD7520AG  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD7520AO  POINT  347380.860 3138500.455 15.99
SO LOCATION  LD7520BG  POINT  347429.354 3138500.417 15.34
SO LOCATION  LD7520BO  POINT  347429.354 3138500.417 15.34
   LOCATION  HEATER  POINT  347374.331 3138501.899 16.13
**
** Source Parameter Cards:
** POINT:   SRCID              QS        HS         TS         VS         DS
**                            (g/s)      (m)        (K)       (m/s)       (m)
** Source Parameters **
** 75% Load, 20 F, Natural Gas firing = 2390 hr/yr
** = 51.75  lb/hr * 2390/8760hrs/yr = 14.12 lb/hr = 1.778 annualized g/s
SO SRCPARAM   LD7520AG    1.78       22.9       922.0     28.06      6.71
SO SRCPARAM   LD7520BG    1.78       22.9       922.0     28.06      6.71
** 75% Load, 20 F, Oil firing = 1000 hr/yr
** = 280.39 lb/hr * 1000 hrs/8760 hrs/yr = 32.009 lb/hr = 4.033 annualized g/s
SO SRCPARAM   LD7520AO    4.03       22.9       919.8     28.44      6.71
SO SRCPARAM   LD7520BO    4.03       22.9       919.8     28.44      6.71

** HEATER  0.95 lb/hr * 3390/8760 hrs/yr = 0.368 lb/hr = 0.0464 annualized g/s
   SRCPARAM   HEATER    0.0464     9.14      533.2    16.15      0.31
**
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID LD7520AG     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD7520AG    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID LD7520AG    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID LD7520AG     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD7520AG    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID LD7520AG    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN LD7520AG     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD7520AG     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN LD7520AG    11.11    11.25    11.06    10.52     9.67     8.53
SO BUILDLEN LD7520AG     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN LD7520AG     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN LD7520AG    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ    LD7520AG     2.47     1.74     0.97     0.16    -0.65    -1.44
SO XBADJ    LD7520AG    -2.18    -2.86    -3.46    -5.42    -7.23    -8.81
SO XBADJ    LD7520AG   -10.13   -11.14   -11.81   -12.12   -12.06   -11.64
SO XBADJ    LD7520AG   -12.14   -12.27   -12.03   -11.42   -10.46    -9.19
SO XBADJ    LD7520AG    -7.64    -5.85    -3.89    -3.29    -2.59    -1.81
SO XBADJ    LD7520AG    -0.98    -0.12     0.75     1.59     2.39     3.11
SO YBADJ    LD7520AG     1.07     2.32     3.50     4.57     5.51     6.28
SO YBADJ    LD7520AG     6.86     7.23     7.38     7.30     7.01     6.50
SO YBADJ    LD7520AG     5.79     4.91     3.88     2.73     1.50     0.22
SO YBADJ    LD7520AG    -1.07    -2.32    -3.50    -4.57    -5.51    -6.28
SO YBADJ    LD7520AG    -6.86    -7.23    -7.38    -7.30    -7.01    -6.50
SO YBADJ    LD7520AG    -5.79    -4.91    -3.88    -2.73    -1.50    -0.22
**
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT LD7520AO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID LD7520AO     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD7520AO    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID LD7520AO    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID LD7520AO     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID LD7520AO    10.52     9.67     8.53     9.67    10.52    11.06
```

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SO BUILDWID  LD7520AO    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN  LD7520AO     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520AO     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN  LD7520AO    11.11    11.25    11.06    10.52     9.67     8.53
SO BUILDLEN  LD7520AO     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520AO     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN  LD7520AO    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ     LD7520AO     2.47     1.74     0.97     0.16    -0.65    -1.44
SO XBADJ     LD7520AO    -2.18    -2.86    -3.46    -5.42    -7.23    -8.81
SO XBADJ     LD7520AO   -10.13   -11.14   -11.81   -12.12   -12.06   -11.64
SO XBADJ     LD7520AO   -12.14   -12.27   -12.03   -11.42   -10.46    -9.19
SO XBADJ     LD7520AO    -7.64    -5.85    -3.89    -3.29    -2.59    -1.81
SO XBADJ     LD7520AO    -0.98    -0.12     0.75     1.59     2.39     3.11
SO YBADJ     LD7520AO     1.07     2.32     3.50     4.57     5.51     6.28
SO YBADJ     LD7520AO     6.86     7.23     7.38     7.30     7.01     6.50
SO YBADJ     LD7520AO     5.79     4.91     3.88     2.73     1.50     0.22
SO YBADJ     LD7520AO    -1.07    -2.32    -3.50    -4.57    -5.51    -6.28
SO YBADJ     LD7520AO    -6.86    -7.23    -7.38    -7.30    -7.01    -6.50
SO YBADJ     LD7520AO    -5.79    -4.91    -3.88    -2.73    -1.50    -0.22
**
SO BUILDHGT  LD7520BG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BG     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT  LD7520BG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BG     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT  LD7520BG     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID  LD7520BG     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID  LD7520BG    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID  LD7520BG    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID  LD7520BG     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID  LD7520BG    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID  LD7520BG    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN  LD7520BG     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520BG     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN  LD7520BG    11.11    11.25    11.06    10.52     9.67     8.52
SO BUILDLEN  LD7520BG     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520BG     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN  LD7520BG    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ     LD7520BG     3.30     2.47     1.56     0.60    -0.37    -1.34
SO XBADJ     LD7520BG    -2.26     0.00     0.00    -5.99    -7.93    -9.63
SO XBADJ     LD7520BG   -11.04   -12.11   -12.81   -13.12   -13.04   -12.56
SO XBADJ     LD7520BG   -12.97   -12.99   -12.61   -11.86   -10.74    -9.29
SO XBADJ     LD7520BG    -7.56     0.00     0.00    -2.72    -1.89    -1.00
SO XBADJ     LD7520BG    -0.07     0.85     1.75     2.60     3.37     4.03
SO YBADJ     LD7520BG     1.63     3.02     4.32     5.48     6.48     7.28
SO YBADJ     LD7520BG     7.86     0.00     0.00     8.14     7.73     7.09
SO YBADJ     LD7520BG     6.23     5.18     3.98     2.65     1.25    -0.20
SO YBADJ     LD7520BG    -1.63    -3.02    -4.32    -5.48    -6.48    -7.28
SO YBADJ     LD7520BG    -7.86     0.00     0.00    -8.14    -7.73    -7.09
SO YBADJ     LD7520BG    -6.23    -5.18    -3.98    -2.65    -1.25     0.20
**
SO BUILDHGT  LD7520BO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BO     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT  LD7520BO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT  LD7520BO     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT  LD7520BO     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID  LD7520BO     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID  LD7520BO    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID  LD7520BO    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID  LD7520BO     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID  LD7520BO    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID  LD7520BO    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN  LD7520BO     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520BO     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN  LD7520BO    11.11    11.25    11.06    10.52     9.67     8.52
SO BUILDLEN  LD7520BO     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN  LD7520BO     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN  LD7520BO    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ     LD7520BO     3.30     2.47     1.56     0.60    -0.37    -1.34
SO XBADJ     LD7520BO    -2.26     0.00     0.00    -5.99    -7.93    -9.63
SO XBADJ     LD7520BO   -11.04   -12.11   -12.81   -13.12   -13.04   -12.56
SO XBADJ     LD7520BO   -12.97   -12.99   -12.61   -11.86   -10.74    -9.29
SO XBADJ     LD7520BO    -7.56     0.00     0.00    -2.72    -1.89    -1.00
SO XBADJ     LD7520BO    -0.07     0.85     1.75     2.60     3.37     4.03
SO YBADJ     LD7520BO     1.63     3.02     4.32     5.48     6.48     7.28
SO YBADJ     LD7520BO     7.86     0.00     0.00     8.14     7.73     7.09
SO YBADJ     LD7520BO     6.23     5.18     3.98     2.65     1.25    -0.20
SO YBADJ     LD7520BO    -1.63    -3.02    -4.32    -5.48    -6.48    -7.28
SO YBADJ     LD7520BO    -7.86     0.00     0.00    -8.14    -7.73    -7.09
SO YBADJ     LD7520BO    -6.23    -5.18    -3.98    -2.65    -1.25     0.20
**
```

```
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    0.00    0.00    0.00   14.33   14.33
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER      6.71    0.00    0.00    0.00    6.71    6.71
SO BUILDWID HEATER      8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER     10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER     11.25    0.00    0.00    0.00   14.73   13.36
SO BUILDWID HEATER      8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER     10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER     11.25    0.00    0.00    0.00    8.72    7.35
SO BUILDLEN HEATER      9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER     11.11    0.00    0.00    0.00   11.24    9.06
SO BUILDLEN HEATER      9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER      9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER     11.11    0.00    0.00    0.00    9.67    8.53
SO XBADJ    HEATER      2.18    2.62    2.98    3.25    3.43    3.50
SO XBADJ    HEATER      3.46    3.32    3.07    1.26   -0.60   -2.44
SO XBADJ    HEATER     -4.20    0.00    0.00    0.00  -80.88  -80.15
SO XBADJ    HEATER    -11.85  -13.14  -14.04  -14.51  -14.54  -14.12
SO XBADJ    HEATER    -13.28  -12.03  -10.42   -9.97   -9.22   -8.19
SO XBADJ    HEATER     -6.91    0.00    0.00    0.00   -0.17    1.67
SO YBADJ    HEATER     -5.61   -4.31   -2.88   -1.36    0.21    1.76
SO YBADJ    HEATER      3.27    4.67    5.93    7.01    7.88    8.51
SO YBADJ    HEATER      8.88    0.00    0.00    0.00    8.66   -4.54
SO YBADJ    HEATER      5.61    4.31    2.88    1.36   -0.21   -1.76
SO YBADJ    HEATER     -3.27   -4.67   -5.93   -7.01   -7.88   -8.51
SO YBADJ    HEATER     -8.88    0.00    0.00    0.00   -7.67   -6.75

SO SRCGROUP ALL
**
SO FINISHED

RE STARTING
   INCLUDED sh0308.rou
RE FINISHED
**
*****************************************
** AERMOD Meteorology Pathway
*****************************************
**
**
ME STARTING
   SURFFILE C:\amodmet\TPATPA01.SFC
   PROFFILE C:\amodmet\TPATPA01.PFL
   SURFDATA 12842 2001 TAMPA/INT'L_ARPT
   UAIRDATA 12842 2001 TAMPA/INT'L_ARPT
   PROFBASE 19 FEET
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

AERBOB RELEASE 020304 .

AERMOD OUTPUT FILE NUMBER 1 :noxsig.o01
AERMOD OUTPUT FILE NUMBER 2 :noxsig.o02
AERMOD OUTPUT FILE NUMBER 3 :noxsig.o03
AERMOD OUTPUT FILE NUMBER 4 :noxsig.o04
AERMOD OUTPUT FILE NUMBER 5 :noxsig.o05
First title for last output file is: 2001 SHADY HILLS 2 SC CTS + Heater NOx SIG ANALYSIS 3/28/08
Second title for last output file is: CTs on Natural Gas 2390 hr/yr and fuel oil 1000 hr/yr

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL					
Annual					
	2001	0.407	347311.	3138412.	01123124
	2002	0.355	347311.	3138412.	02123124
	2003	0.378	347311.	3138412.	03123124
	2004	0.362	347483.	3138545.	04123124
	2005	0.575	347311.	3138412.	05123124

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00

```
CO STARTING
CO TITLEONE 2001 SHADY HILLS 2 SC CTS + Heater CO SIG ANALYSIS   4/2/08
CO TITLETWO CTs on Fuel Oil
CO MODELOPT DFAULT CONC   NOWARN
CO AVERTIME  8 1
CO POLLUTID CO
CO RUNORNOT RUN
CO FINISHED

SO STARTING

** Source Location Cards:
** ------------------------
**  A -  CT 4
**  B -  CT 5
** Source Location Cards:
**          SRCID SRCTYP        XS          YS          ZS
**   UTM                        (m)         (m)         (m)
SO LOCATION  BASE20A  POINT  347380.860 3138500.455 15.99
SO LOCATION  BASE20B  POINT  347429.354 3138500.417 15.34
   LOCATION  HEATER  POINT  347374.331 3138501.899 16.13
**
** Source Parameter Cards:
** POINT:    SRCID          QS        HS         TS        VS        DS
**                        (g/s)       (m)        (K)      (m/s)      (m)
** Source Parameters **
** Base Load, 20 F, Oil firing
SO SRCPARAM   BASE20A    8.96       22.9       840.4     35.19      6.71
SO SRCPARAM   BASE20B    8.96       22.9       840.4     35.19      6.71

   SRCPARAM   HEATER    0.101      9.14      533.2     16.15      0.31
**
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20A     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE20A     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID BASE20A    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID BASE20A    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID BASE20A     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID BASE20A    10.52     9.67     8.53     9.67    10.52    11.06
SO BUILDWID BASE20A    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN BASE20A     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN BASE20A     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN BASE20A    11.11    11.25    11.06    10.52     9.67     8.53
SO BUILDLEN BASE20A     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN BASE20A     9.82     8.72     7.35     8.72     9.82    10.63
SO BUILDLEN BASE20A    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ    BASE20A     2.47     1.74     0.97     0.16    -0.65    -1.44
SO XBADJ    BASE20A    -2.18    -2.86    -3.46    -5.42    -7.23    -8.81
SO XBADJ    BASE20A   -10.13   -11.14   -11.81   -12.12   -12.06   -11.64
SO XBADJ    BASE20A   -12.14   -12.27   -12.03   -11.42   -10.46    -9.19
SO XBADJ    BASE20A    -7.64    -5.85    -3.89    -3.29    -2.59    -1.81
SO XBADJ    BASE20A    -0.98    -0.12     0.75     1.59     2.39     3.11
SO YBADJ    BASE20A     1.07     2.32     3.50     4.57     5.51     6.28
SO YBADJ    BASE20A     6.86     7.23     7.38     7.30     7.01     6.50
SO YBADJ    BASE20A     5.79     4.91     3.88     2.73     1.50     0.22
SO YBADJ    BASE20A    -1.07    -2.32    -3.50    -4.57    -5.51    -6.28
SO YBADJ    BASE20A    -6.86    -7.23    -7.38    -7.30    -7.01    -6.50
SO YBADJ    BASE20A    -5.79    -4.91    -3.88    -2.73    -1.50    -0.22
**
SO BUILDHGT BASE20B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20B     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT BASE20B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDHGT BASE20B     6.71     0.00     0.00     6.71     6.71     6.71
SO BUILDHGT BASE20B     6.71     6.71     6.71     6.71     6.71     6.71
SO BUILDWID BASE20B     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID BASE20B    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID BASE20B    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDWID BASE20B     8.72     9.82    10.63    11.11    11.25    11.06
SO BUILDWID BASE20B    10.52     0.00     0.00     9.67    10.52    11.06
SO BUILDWID BASE20B    11.25    11.11    10.63     9.82     8.72     7.35
SO BUILDLEN BASE20B     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN BASE20B     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN BASE20B    11.11    11.25    11.06    10.52     9.67     8.52
SO BUILDLEN BASE20B     9.67    10.52    11.06    11.25    11.11    10.63
SO BUILDLEN BASE20B     9.82     0.00     0.00     8.72     9.82    10.63
SO BUILDLEN BASE20B    11.11    11.25    11.06    10.52     9.67     8.53
SO XBADJ    BASE20B     3.30     2.47     1.56     0.60    -0.37    -1.34
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SO XBADJ      BASE20B    -2.26    0.00    0.00   -5.99   -7.93   -9.63
SO XBADJ      BASE20B   -11.04  -12.11  -12.81  -13.12  -13.04  -12.56
SO XBADJ      BASE20B   -12.97  -12.99  -12.61  -11.86  -10.74   -9.29
SO XBADJ      BASE20B    -7.56    0.00    0.00   -2.72   -1.89   -1.00
SO XBADJ      BASE20B    -0.07    0.85    1.75    2.60    3.37    4.03
SO YBADJ      BASE20B     1.63    3.02    4.32    5.48    6.48    7.28
SO YBADJ      BASE20B     7.86    0.00    0.00    8.14    7.73    7.09
SO YBADJ      BASE20B     6.23    5.18    3.98    2.65    1.25   -0.20
SO YBADJ      BASE20B    -1.63   -3.02   -4.32   -5.48   -6.48   -7.28
SO YBADJ      BASE20B    -7.86    0.00    0.00   -8.14   -7.73   -7.09
SO YBADJ      BASE20B    -6.23   -5.18   -3.98   -2.65   -1.25    0.20
**
SO BUILDHGT HEATER        6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER        6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER        6.71    0.00    0.00    0.00   14.33   14.33
SO BUILDHGT HEATER        6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER        6.71    6.71    6.71    6.71    6.71    6.71
SO BUILDHGT HEATER        6.71    0.00    0.00    0.00    6.71    6.71
SO BUILDWID HEATER        8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER       10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER       11.25    0.00    0.00    0.00   14.73   13.36
SO BUILDWID HEATER        8.72    9.82   10.63   11.11   11.25   11.06
SO BUILDWID HEATER       10.52    9.67    8.53    9.67   10.52   11.06
SO BUILDWID HEATER       11.25    0.00    0.00    0.00    8.72    7.35
SO BUILDLEN HEATER        9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER        9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER       11.11    0.00    0.00    0.00   11.24    9.06
SO BUILDLEN HEATER        9.67   10.52   11.06   11.25   11.11   10.63
SO BUILDLEN HEATER        9.82    8.72    7.35    8.72    9.82   10.63
SO BUILDLEN HEATER       11.11    0.00    0.00    0.00    9.67    8.53
SO XBADJ      HEATER      2.18    2.62    2.98    3.25    3.43    3.50
SO XBADJ      HEATER      3.46    3.32    3.07    1.26   -0.60   -2.44
SO XBADJ      HEATER     -4.20    0.00    0.00    0.00  -80.88  -80.15
SO XBADJ      HEATER    -11.85  -13.14  -14.04  -14.51  -14.54  -14.12
SO XBADJ      HEATER    -13.28  -12.03  -10.42   -9.97   -9.22   -8.19
SO XBADJ      HEATER     -6.91    0.00    0.00    0.00   -0.17    1.67
SO YBADJ      HEATER     -5.61   -4.31   -2.88   -1.36    0.21    1.76
SO YBADJ      HEATER      3.27    4.67    5.93    7.01    7.88    8.51
SO YBADJ      HEATER      8.88    0.00    0.00    0.00    8.66   -4.54
SO YBADJ      HEATER      5.61    4.31    2.88    1.36   -0.21   -1.76
SO YBADJ      HEATER     -3.27   -4.67   -5.93   -7.01   -7.88   -8.51
SO YBADJ      HEATER     -8.88    0.00    0.00    0.00   -7.67   -6.75


SO SRCGROUP ALL
**
SO FINISHED

RE STARTING
   INCLUDED sh0308.rou
RE FINISHED
**
*****************************************
** AERMOD Meteorology Pathway
*****************************************
**
**
ME STARTING
   SURFFILE C:\amodmet\TPATPA01.SFC
   PROFFILE C:\amodmet\TPATPA01.PFL
   SURFDATA 12842 2001 TAMPA/INT'L_ARPT
   UAIRDATA 12842 2001 TAMPA/INT'L_ARPT
   PROFBASE 19 FEET
ME FINISHED

OU STARTING
OU RECTABLE ALLAVE FIRST
OU FINISHED
```

AERBOS RELEASE 020304

AERMOD OUTPUT FILE NUMBER 1 :COSIG.001
AERMOD OUTPUT FILE NUMBER 2 :COSIG.002
AERMOD OUTPUT FILE NUMBER 3 :COSIG.003
AERMOD OUTPUT FILE NUMBER 4 :COSIG.004
AERMOD OUTPUT FILE NUMBER 5 :COSIG.005
First title for last output file is: 2001 SHADY HILLS 2 SC CTS + Heater CO SIG ANALYSIS 4/2/08
Second title for last output file is: CTs on Fuel Oil

AVERAGING TIME	YEAR	CONC (ug/m3)	X (m)	Y (m)	PERIOD ENDING (YYMMDDHH)
SOURCE GROUP ID: ALL					
HIGH 8-Hour					
	2001	13.037	347350.	3138400.	01110516
	2002	15.524	347311.	3138412.	02052108
	2003	15.060	347311.	3138412.	03110924
	2004	13.173	347311.	3138412.	04110916
	2005	14.561	347311.	3138412.	05103008
HIGH 1-Hour					
	2001	20.750	347350.	3138400.	01010409
	2002	20.648	347350.	3138400.	02010409
	2003	21.234	347350.	3138400.	03010706
	2004	21.669	347311.	3138412.	04121524
	2005	21.268	347311.	3138412.	05020420

All receptor computations reported with respect to a user-specified origin

GRID	0.00	0.00
DISCRETE	0.00	0.00