Florida Department of
Environmental Protection

Memorandum

TO: Michael Clark, Finance and Accounting

FROM: Al Linero *aaf 2/10*

DATE: February 10, 1999

SUBJ: TECO Polk Power Station Site Certification Fee
PA 92-32, Module No. 8042

Attached with this memo is a check for $7500. This fee should be applied toward the Site Certification modification fee of $10,000. Buck Oven will inform the company that they must submit an additional $2,500 before we begin work on TECO's request.

AL/kt

cc: B. Oven, PPS
P. Adams, BAR
C. H. Fancy, BAR

TECO

TAMPA ELECTRIC

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FEB 08 1999

BUREAU OF
AIR REGULATION

February 5, 1999

Mr. Clair Fancy
Florida Department of Environmental Protection
Bureau of Air Regulation
111 Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 809689309646

Re: Tampa Electric Company
~~Big Bend Station Units 1 and 2~~ Polk Power Station
~~Flue Gas Desulfurization (FGD) System~~ Two Simple Cycle Turbines
Construction Permit Application

PA 92-32
module 8042
PSD-FL-263

Dear Mr. Fancy:

Please find enclosed four (4) signed and sealed copies, including the Electronic Submission of Application (ELSA), of Tampa Electric Company's (TEC) permit application to construct two new simple-cycle combustion turbines at the Polk Power Station site. A check for $7,500.00 to the Florida Department of Environmental Protection is enclosed to cover the processing fee per 62-4.050(4)(a)1.

TEC appreciates your timely review and processing of this construction permit application. If you should have any questions, please feel free to call me at (813) 641-5033.

Sincerely,

James Hunter
Administrator - Air Programs
Environmental Planning

EP\gm\jjh897

Enclosures

c: A.A. Linero, FDEP - Tallahassee
R.D. Garrity, Ph.D., FDEP-Tampa ✓

CC: T. Heron ✓
B. Oven ✓
C. Holladay
Polk Co. ✓
EPA ✓
NPS ✓
File

Original sent
to M. Clark, F&A
2/10/99

Site Cert.

Tampa Electric Company FLORIDA DEPT OF ENVIRONMENTAL 0904017

Invoice Date	Invoice Number	G/L Account	Description	Invoice Amount
2/3/99	PERMIT	M06471	PERMIT FEE POLK CT	7,500.00
			Check Total	7,500.00

FOR SECURITY PURPOSES, THE BORDER OF THIS DOCUMENT CONTAINS MICROPRINTING

TECO
TAMPA ELECTRIC

Tampa Electric Company
Post Office Box 3285
702 North Franklin Street
Tampa, Florida 33601

NationsBank
NationsBank of Georgia NA

Check Number
0904017

64-1278-8
611

Check Date	Check Amount
2/4/99	******$7,500.00

PAY Seven Thousand Five Hundred Dollars and 00/100 Cents

TO THE ORDER OF FLORIDA DEPT OF ENVIRONMENTAL PROTECTION

RAWalk

THE REVERSE SIDE OF THIS DOCUMENT INCLUDES AN ARTIFICIAL WATERMARK - HOLD AT AN ANGLE TO VIEW

⑈0904017⑈ ⑆061112788⑆010 116 3492⑈

POLK POWER STATION
SIMPLE-CYCLE COMBUSTION TURBINES
AIR CONSTRUCTION PERMIT APPLICATION

RECEIVED
FEB 08 1999
BUREAU OF
AIR REGULATION

Prepared for:

TECO
TAMPA ELECTRIC

Prepared by:

ECT
Environmental Consulting & Technology, Inc.
3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 98637-0100

February 1999

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) is planning to construct and operate two simple-cycle combustion turbine generators (CTGs) at its existing Polk Power Station located in Polk County, Florida. The Polk Power Station is situated approximately 17 miles south of the City of Lakeland, approximately 11 miles south of the City of Mulberry, and approximately 13 miles southwest of the City of Bartow in southwest Polk County. The Polk Power Station Combustion Turbine Project (Project) will consist of two, nominal 165-megawatt (MW) CTGs fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. The new simple-cycle CTGs will operate at annual capacity factors up to 50 and 10 percent for natural gas and oil firing, respectively.

Operation of the proposed project will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes TEC's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, *et. seq.*, F.A.C.

The Project will be located in an attainment area and will have potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). The Project qualifies as a major modification to an existing major source and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Section 62-212.400, F.A.C. Therefore, this report and application are also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.

- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the Project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 lists the references used in preparing the report.

Attachments A through D provide the FDEP Application for Air Permit—Long Form, CTG vendor emissions data, control system vendor quote, and emission rate calculations, respectively. Emission rate calculations and all dispersion modeling input and output files for the ambient impact analysis are provided in diskette format in Attachment E.

1.2 SUMMARY

The Project will consist of two nominal 165-MW General Electric (GE) PG7241 (FA) CTGs. The CTGs will be fired with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf). Low sulfur (containing no more than 0.05 weight percent sulfur [wt%S]) will serve as a back-up fuel source.

The planned construction start date for the Project is October 1999. For the first CTG, the projected date for the facility to begin commercial operation is June 2000, following initial equipment start-up and completion of required performance testing. The second CTG is projected to begin commercial operation in January 2003.

Based on an evaluation of anticipated worst-case annual operating scenarios, the Project will have the potential to emit 581.0 tpy of nitrogen oxides (NO_x), 303.2 tpy of carbon monoxide (CO), 66.2 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM/PM_{10}), 126.4 tpy of sulfur dioxide (SO_2), and 73.6 tpy of volatile organic compounds

(VOCs). Regarding noncriteria pollutants, the Project will potentially emit 14.6 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of heavy metals and organic compounds associated with distillate fuel oil combustion. Based on these annual emission rate potentials, NO_x, CO, PM/PM_{10}, SO_2, VOC, and H_2SO_4 mist emissions are subject to PSD review.

As presented in this report, the analyses required for this permit application resulted in the following conclusions:

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. The CTGs will utilize the latest burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates and will be fired with pipeline-quality natural gas and low-sulfur, low-ash distillate fuel oil.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs for the CTGs. At baseload operation during natural gas and distillate fuel oil firing, the CTG CO exhaust concentrations are projected to be 15 and 33 parts per million by dry volume dry (ppmvd), respectively. At baseload operation during natural gas and distillate fuel oil firing, the CTG VOC exhaust concentrations are projected to be 7 ppmvd. These concentrations are consistent with prior FDEP BACT determinations for CTGs. Cost effectiveness of a CO oxidation catalyst control system was determined to be $3,652 per ton of CO. Because this cost exceeds values previously determined by FDEP to be cost effective, installation of a CO oxidation catalyst control system is considered to be economically unreasonable.
- BACT for SO_2 and H_2SO_4 mist will be achieved through the use of low-sulfur, pipeline-quality natural gas containing no more than 2.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S.
- Dry low-NO_x burner technology is proposed as BACT for NO_x for the Project CTGs during natural gas firing. For all normal operating loads, the CTG NO_x exhaust concentration will not exceed 10.5 ppmvd, corrected to 15 percent oxygen (O_2). This concentration is consistent with prior FDEP BACT determinations for simple cycle CTGs. Cost effectiveness of a selective catalytic reduction (SCR) control system was determined to be $9,717 per ton of NO_x. Because this cost exceeds values pre-

viously determined by FDEP to be cost effective, installation of an SCR control system is considered to be economically unreasonable. During distillate fuel oil firing, wet injection will be employed to reduce the CTG NO_x exhaust concentration to 42 ppmvd, corrected to 15 percent O_2.

- The Project is projected to emit NO_x, CO, PM/PM_{10}, SO_2, VOC, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the Project qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(260), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class I and II increment consumption was not required.
- Based on refined dispersion modeling, the Project will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Chassahowitzka National Wildlife Refuge) is located approximately 120 kilometers (km) northwest of the project site. Air quality and visibility impacts on this Class I area will be negligible.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed two new, simple-cycle CTGs will be located at the existing Tampa Electric Company Polk Power Station. The Polk Power Station is situated approximately 17 miles south of the City of Lakeland, approximately 11 miles south of the City of Mulberry, and approximately 13 miles southwest of the City of Bartow in southwest Polk County, Florida. Figure 2-1 shows the location of the Polk Power Station within the State of Florida. A vicinity location map and Polk Power Station property boundaries are provided in Figure 2-2. Figure 2-3 provides portions of a U.S. Geological Survey (USGS) topographical map showing the Polk Power Station site location and nearby prominent geographical features.

The proposed Project consists of two, simple-cycle GE PG7241 (FA) CTGs. Each of the two CTGs will be capable of producing a nominal 165 MW of electricity for an overall total nominal generation capacity of 330 MW. The CTGs will be fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source.

The new simple-cycle CTGs will operate at annual capacity factors up to 50 and 10 percent for natural gas and oil firing, respectively. At baseload operation, these annual capacity factors are equivalent to 4,380 and 876 hours per year (hr/yr) for natural gas and oil firing, respectively. Annual CTG operating hours will increase with lower load operations. The CTGs will normally operate between 50- and 100-percent load.

Combustion of natural gas and distillate fuel oil in the CTGs will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Emission control systems proposed for the simple-cycle CTGs include the use of dry low-NO_x combustors (natural gas firing) and water injection (distillate fuel oil firing) for control of NO_x; good combustion practices for abatement of CO; and use of clean, low-sulfur, low-ash natural natural gas and distillate fuel oil to minimize PM, SO_2, and H_2SO_4 mist emissions.

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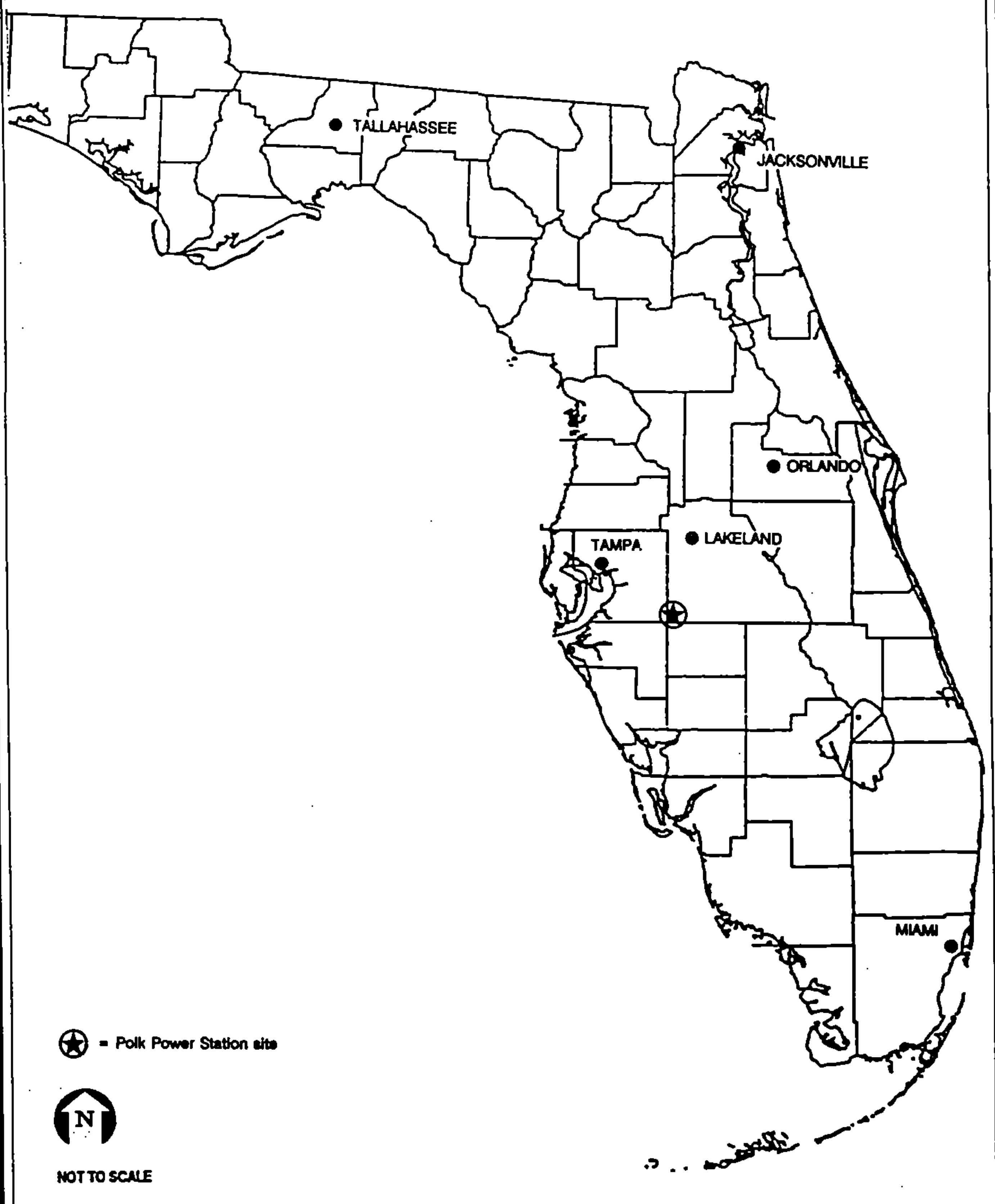

FIGURE 2-1.
LOCATION OF THE POLK POWER STATION WITHIN THE STATE OF FLORIDA

Source: ECT, 1998.

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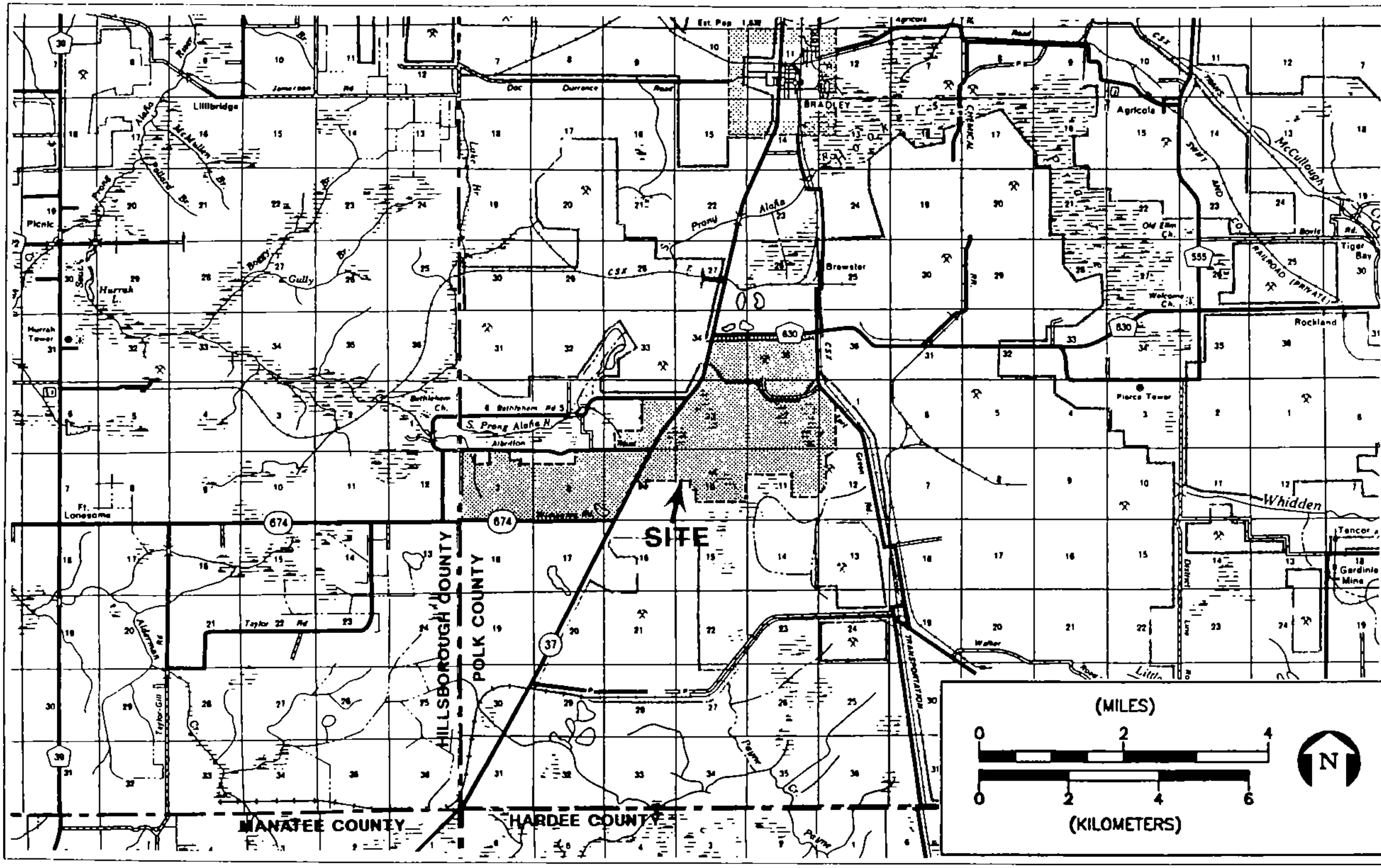

FIGURE 2-2.

POLK POWER STATION AREA MAP

Source: FDOT Map; ECT, 1998.

TECO
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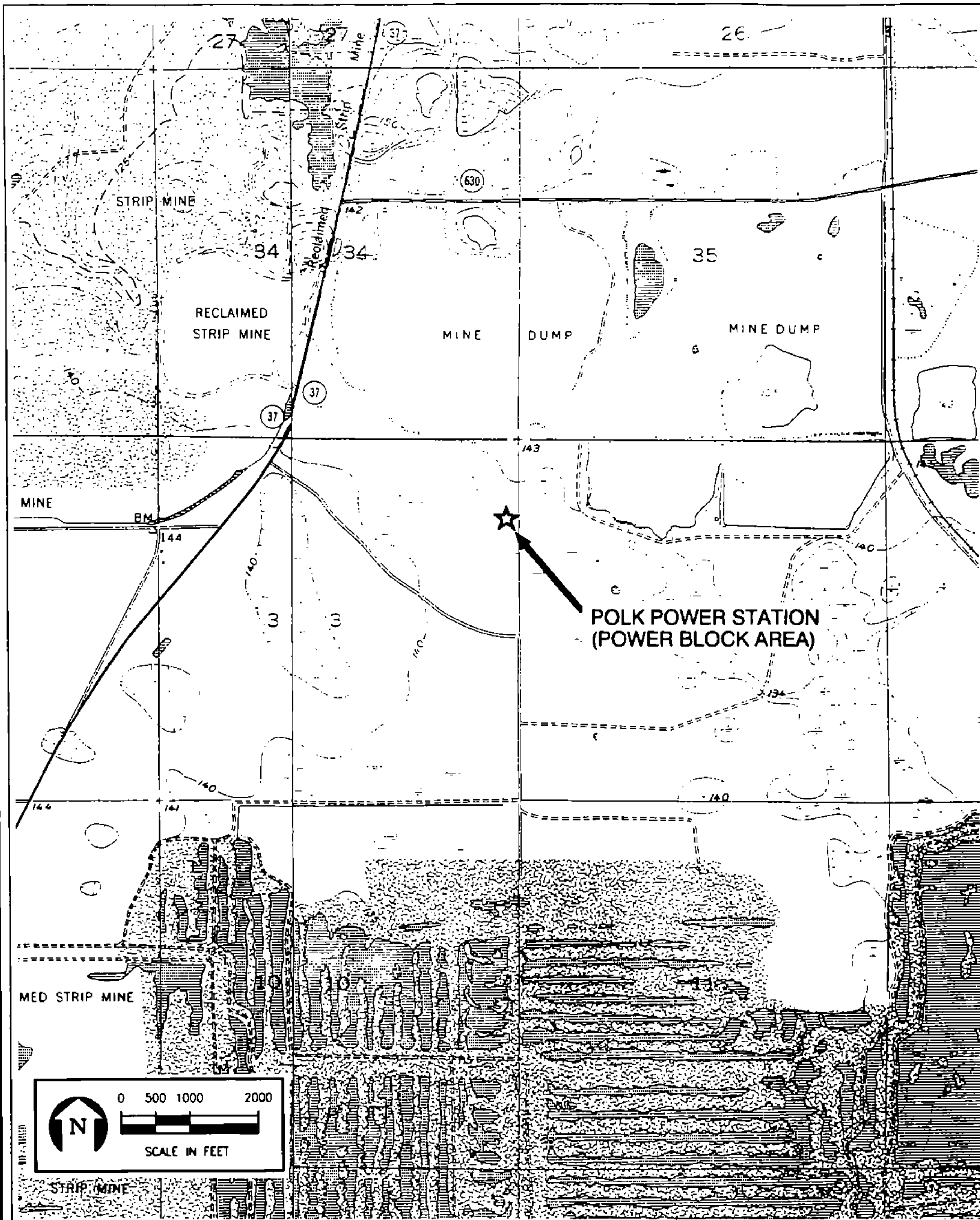

FIGURE 2-3.

POLK POWER STATION LOCATION AND SURROUNDINGS

Source: USGS Quods: Duette NE, FL, 1987; Baird, FL, 1987.

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Figure 2-4 illustrates a plot plan showing Polk Power Station fencelines, major process equipment and structures, and the new CTG emission points. Primary access to the Polk Power Station plant is from State Road 37 on the west side of the site. The Polk Power Station entrance has security to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed Project will include two nominal 165-MW simple-cycle CTGs. Figure 2-5 presents a process flow diagram of the Project.

CTGs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. During warm days when the ambient air temperature exceeds 65 degrees Fahrenheit (°F), the turbine inlet ambient air will be cooled by an evaporative cooler, thus providing denser air for combustion and improving the power output. The compressed combustion air is then combined with natural gas fuel or distillate fuel oil and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power, which is used to drive an electric generator as well as the CTG combustion air compressor.

Normal operation is expected to consist of both CTGs operating at baseload. Alternate operating modes include reduced load (i.e., between 50 and 100 percent of baseload) operation for one or both of the CTGs depending on power demands and use of inlet air evaporative cooling under high ambient temperature conditions. As noted previously, the simple-cycle CTGs may operate at annual capacity factors up to 50 and 10 percent for natural gas and oil firing, respectively.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shut-down, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG warm and cold start periods will last for 180 and 240 minutes,

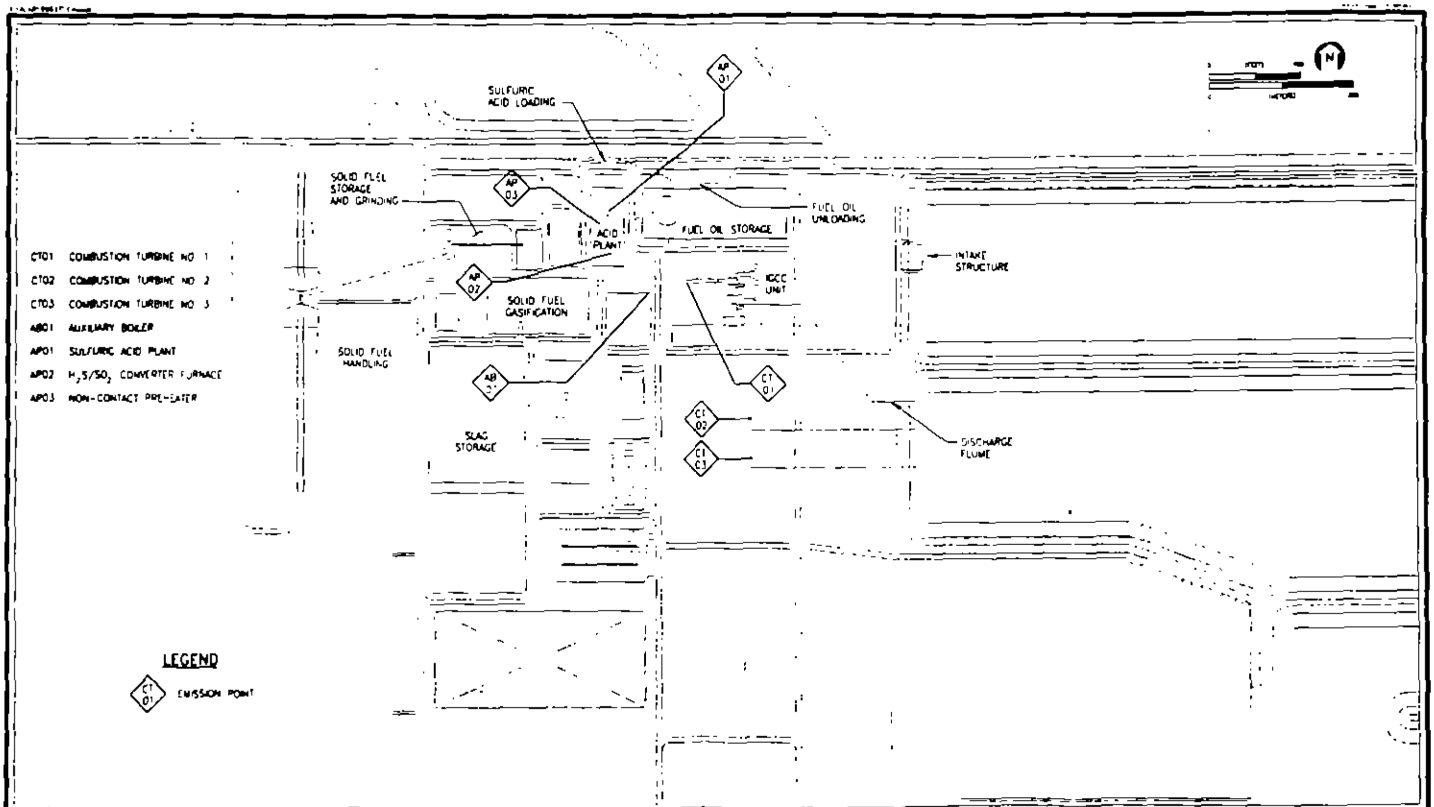

FIGURE 2-4

POLK POWER STATION PLOT PLAN

Source: BECHTEL, 1994; ECT, 1998.

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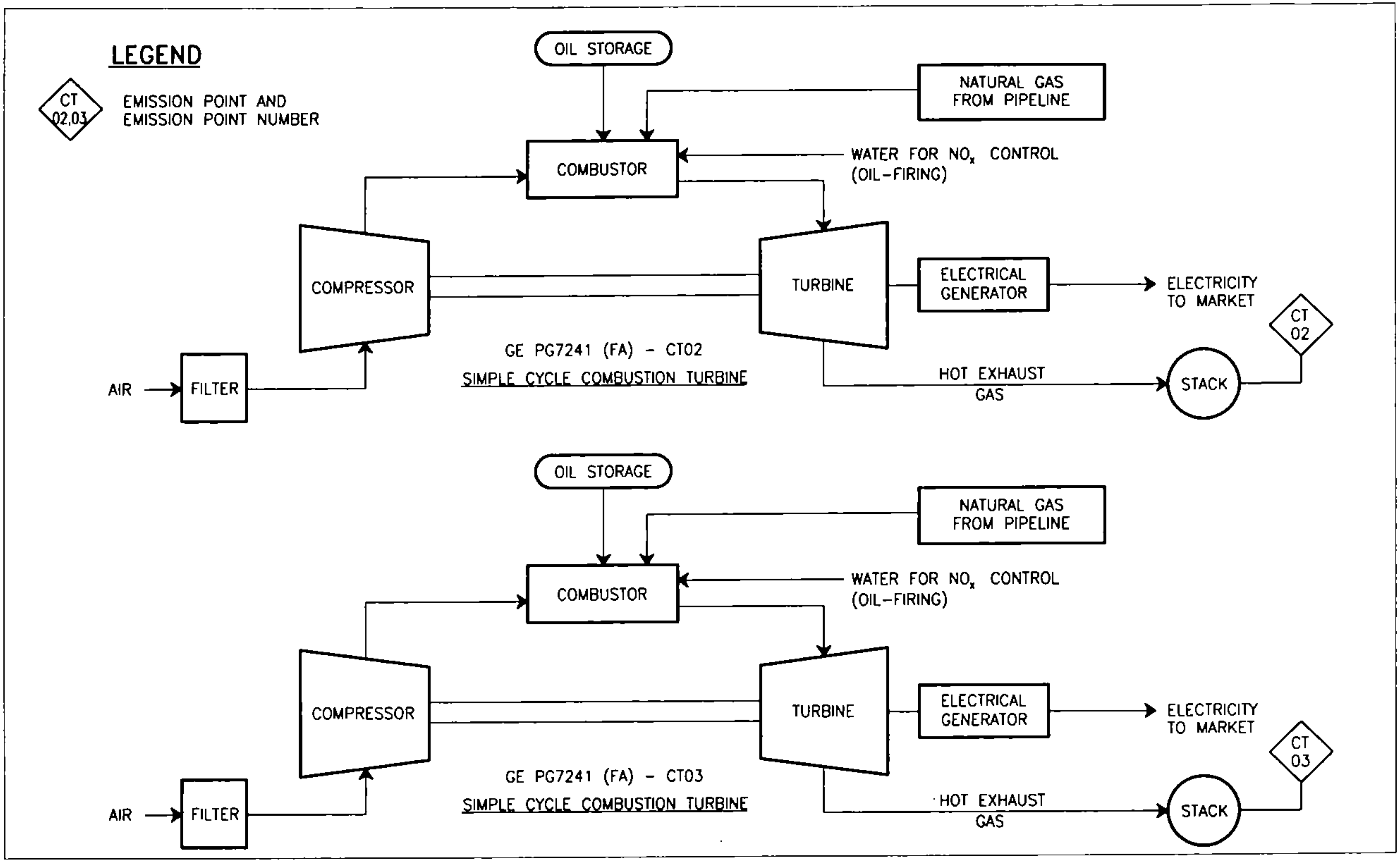

FIGURE 2-5.
SIMPLE CYCLE COMBUSTION TURBINE: PROCESS FLOW DIAGRAM

Source: ECT, 1999.

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respectively, excess emissions for up to 4 hours in any 24-hour period are requested for the new simple-cycle CTGs. CTG start-up/shut-down is defined as that period of time from initiation of CTG firing until the unit reaches steady-state load operation. Steady-state operation is reached when the CTG reaches minimum load (i.e., 50-percent load). A warm start is defined as a start-up that occurs when a CTG has been down for more than 2 hours and less than or equal to 48 hours. A cold start is defined as a start-up that occurs when a CTG has been down for more than 48 hours.

The CTGs will utilize dry low-NO_x combustion technology and water injection to control NO_x air emissions. The use of low-sulfur natural gas and distillate fuel oil in the CTGs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant CTG emission rates for natural gas and distillate fuel oil firing, respectively. Maximum hourly H_2SO_4 emission rates for natural gas and distillate fuel oil firing are summarized in Tables 2-3. Maximum hourly noncriteria pollutant rates for natural gas and distillate fuel oil firing are provided in Tables 2-4 and 2-5, respectively. The highest hourly emission rates for each pollutant are prescribed, taking into account load and ambient temperature to develop maximum hourly emission estimates for each CTG. Noncriteria pollutants consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of distillate fuel oil.

Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CTG operations at low ambient temperature (i.e., 20°F), baseload, and fuel oil firing. The bases for these emission rates are provided in Attachment D.

Table 2-6 presents projected maximum annualized criteria and noncriteria emissions for the Project. The maximum annualized rates were conservatively estimated assuming baseload operation for 4,380 hr/yr (natural gas firing), baseload operation for 876 hr/yr (fuel oil firing) for each CTG, and an ambient temperature of 59°F.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (Per CTG)—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	10.1	1.28	9.8	1.24	73.5	9.26	51.0	6.43	15.0	1.89	Neg.	Neg.
	59	10.1	1.27	9.2	1.16	68.8	8.67	48.0	6.05	14.0	1.76	Neg.	Neg.
	90†	10.0	1.26	8.5	1.07	63.0	7.94	43.0	5.42	13.0	1.64	Neg.	Neg.
75	20	9.9	1.25	7.9	0.99	58.3	7.35	41.0	5.17	12.0	1.51	Neg.	Neg.
	59	9.9	1.24	7.5	0.94	54.8	6.91	39.0	4.91	11.0	1.39	Neg.	Neg.
	90†	9.8	1.23	6.9	0.87	51.3	6.47	36.0	4.54	11.0	1.39	Neg.	Neg.
50	20	9.7	1.23	6.3	0.79	45.5	5.73	34.0	4.28	10.0	1.26	Neg.	Neg.
	59	9.7	1.22	6.0	0.75	43.2	5.44	32.0	4.03	9.0	1.13	Neg.	Neg.
	90†	9.6	1.22	5.6	0.71	40.8	5.15	30.0	3.78	9.0	1.13	Neg.	Neg.

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Includes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 1999.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures (Per CTG)—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	27.0	3.40	104.1	13.12	338.0	42.59	113.0	14.24	15.0	1.89	0.120	0.015
	59	25.3	3.18	98.1	12.36	319.0	40.19	106.0	13.36	14.0	1.76	0.113	0.014
	90†	23.2	2.93	89.2	11.24	290.0	36.54	97.0	12.22	13.0	1.64	0.103	0.013
75	20	20.7	2.61	84.5	10.64	272.0	34.27	84.0	10.58	11.0	1.39	0.097	0.012
	59	20.2	2.54	79.7	10.05	257.0	32.38	81.0	10.21	11.0	1.39	0.092	0.012
	90†	19.4	2.44	73.1	9.20	235.0	29.61	77.0	9.70	11.0	1.39	0.084	0.011
50	20	17.6	2.21	65.9	8.30	210.0	26.46	71.0	8.95	10.0	1.26	0.076	0.010
	59	16.2	2.04	62.7	7.90	200.0	25.20	70.0	8.82	9.0	1.13	0.072	0.009
	90†	15.6	1.97	57.8	7.28	184.0	23.18	67.0	8.44	9.0	1.13	0.067	0.008

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Includes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 1999.

Table 2-3. Maximum H_2SO_4 Pollutant Emission Rates for Three Loads and Three Ambient Temperatures (Per CTG)

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4 lb/hr	Natural Gas H_2SO_4 g/s	Distillate Fuel Oil H_2SO_4 lb/hr	Distillate Fuel Oil H_2SO_4 g/s
100	20	1.1	0.14	12.0	1.51
	59	1.1	0.13	11.3	1.42
	90*	1.0	0.12	10.2	1.29
75	20	0.9	0.11	9.7	1.22
	59	0.9	0.11	9.2	1.15
	90*	0.8	0.10	8.4	1.06
50	20	0.7	0.09	7.6	0.95
	59	0.7	0.09	7.2	0.91
	90*	0.6	0.08	6.6	0.84

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Sources: GE, 1998.
ECT, 1999.

Table 2-4. Maximum Noncriteria Pollutant Emission Rates for 100 Percent and Three Temperatures (Per CTG)—Natural Gas

Unit Load (%)	Ambient Temp. (°F)	Benzene		Dioxins/Furans		Formaldehyde		Mercury		Naphthalene		Polycyclic Organic Matter	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.65E-03	3.34E-04	2.27E-09	2.86E-10	5.49E-02	6.92E-03	1.48E-06	1.86E-07	1.27E-03	1.60E-04	9.47E-05	1.19E-05
	59	2.48E-03	3.13E-04	2.13E-09	2.68E-10	5.14E-02	6.47E-03	1.38E-06	1.74E-07	1.19E-03	1.50E-04	8.86E-05	1.12E-05
	90*	2.28E-03	2.88E-04	1.96E-09	2.47E-10	4.73E-02	5.96E-03	1.27E-06	1.60E-07	1.09E-03	1.38E-04	8.16E-05	1.03E-05

Unit Load (%)	Ambient Temp. (°F)	Toluene	
		lb/hr	g/s
100	20	1.93E-02	2.43E-03
	59	1.81E-02	2.28E-03
	90*	1.66E-02	2.10E-03

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 1999.

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Per CTG)—Distillate Fuel Oil

Unit Load (%)	Ambient Temp. (°F)	Acetaldehyde		Antimony		Arsenic		Benzene		Beryllium		Cadmium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.69E-02	2.13E-03	4.55E-02	5.73E-03	1.01E-02	1.28E-03	2.89E-03	3.64E-04	6.82E-04	8.59E-05	8.68E-03	1.09E-03
	59	1.60E-02	2.01E-03	4.28E-02	5.40E-03	9.54E-03	1.20E-03	2.73E-03	3.43E-04	6.43E-04	8.10E-05	8.18E-03	1.03E-03
	90*	1.45E-02	1.83E-03	3.89E-02	4.91E-03	8.67E-03	1.09E-03	2.48E-03	3.12E-04	5.84E-04	7.36E-05	7.43E-03	9.37E-04

Unit Load (%)	Ambient Temp. (°F)	Chromium		Cobalt		Dioxins/Furans		Ethylbenzene		Formaldehyde		Hydrogen Chloride	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	9.71E-02	1.22E-02	1.88E-02	2.37E-03	2.38E-07	2.99E-08	1.01E-03	1.28E-04	6.20E-02	7.81E-03	5.1	0.65
	59	9.15E-02	1.15E-03	1.77E-02	2.23E-03	2.24E-07	2.82E-08	9.54E-04	1.20E-04	5.84E-02	7.36E-03	4.8	0.61
	90*	8.32E-02	1.05E-03	1.61E-02	2.03E-03	2.04E-07	2.56E-08	8.67E-04	1.09E-04	5.31E-02	6.69E-03	4.4	0.55

Unit Load (%)	Ambient Temp. (°F)	Hydrogen Fluoride		Manganese		Methyl Chloroform		Methylene Chloride		Mercury		Naphthalene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	5.50E-01	6.94E-02	7.02E-01	8.85E-02	1.57E-02	1.98E-03	6.66E-02	8.40E-03	1.88E-03	2.37E-04	7.02E-04	8.85E-05
	59	5.19E-01	6.54E-02	6.62E-01	8.34E-02	1.48E-02	1.86E-03	6.28E-02	7.91E-03	1.77E-03	2.23E-04	6.62E-04	8.34E-05
	90*	4.72E-01	5.94E-02	6.02E-01	7.58E-02	1.35E-02	1.69E-03	5.71E-02	7.19E-03	1.61E-03	2.03E-04	6.02E-04	7.58E-05

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load and Three Temperatures (Per CTG)—Distillate Fuel Oil (Continued, Page 2 of 2)

Unit Load (%)	Ambient Temp. (°F)	Nickel		Phenol		Phosphorus		Polycyclic Organic Matter		Selenium		Tetrachloroethylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.48	3.12E-01	5.02E-02	6.33E-03	6.20E-01	7.81E-02	1.39E-03	1.75E-04	1.09E-02	1.38E-03	1.14E-03	1.43E-04
	59	2.34	2.94E-01	4.73E-02	5.96E-03	5.84E-01	7.36E-02	1.31E-03	1.65E-04	1.03E-02	1.30E-03	1.07E-03	1.35E-04
	90*	2.12	2.68E-01	4.30E-02	5.42E-03	5.31E-01	6.69E-02	1.19E-03	1.50E-04	9.38E-03	1.18E-03	9.74E-04	1.23E-04

Unit Load (%)	Ambient Temp. (°F)	Toluene		Vinyl Acetate		Xylenes	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.65E-02	2.08E-03	1.06E-02	1.34E-03	4.52E-03	5.70E-04
	59	1.56E-02	1.96E-03	1.00E-02	1.26E-03	4.26E-03	5.37E-04
	90*	1.42E-02	1.78E-03	9.12E-03	1.15E-03	3.88E-03	4.88E-04

Note: g/s = gram per second.
lb/hr = pound per hour.
Neg. = negligible

*Emission rates reflect the use of evaporative cooler at ambient temperatures above 65°F.

Source: ECT, 1999.

Table 2-6. Maximum Annualized Emission Rates

Pollutant	Annualized Emission Rates (tpy)		
	Simple-Cycle CTG (CT02)	Simple-Cycle CTG (CT03)	CTG Totals
NO_x	290.5	290.5	581.0
CO	151.6	151.6	303.2
PM/PM_{10}*	33.1	33.1	66.2
SO_2	63.2	63.2	126.4
VOC	36.8	36.8	73.6
H_2SO_4	7.3	7.3	14.6
Acetaldehyde	6.99E-03	6.99E-03	0.0140
Antimony	1.88E-02	1.88E-02	0.0376
Arsenic	4.18E-03	4.18E-03	0.0084
Benzene	6.62E-03	6.62E-03	0.0132
Beryllium	2.81E-04	2.81E-04	0.0006
Cadmium	3.58E-03	3.58E-03	0.0072
Chromium	4.01E-02	4.01E-02	0.0802
Cobalt	7.76E-03	7.76E-03	0.0155
Dioxins/Furans	1.03E-07	1.03E-07	0.0000002
Ethylbenzene	4.18E-04	4.18E-04	0.0008
Formaldehyde	1.39E-01	1.39E-01	0.2780
Hydrogen chloride	2.11	2.11	4.2200
Hydrogen fluoride	2.27E-01	2.27E-01	0.4540
Lead	4.95E-02	4.95E-02	0.0990
Manganese	2.90E-01	2.90E-01	0.5800
Methyl chloroform	6.48E-03	6.48E-03	0.0130
Methylene chloride	2.75E-02	2.75E-02	0.0550
Mercury	7.79E-04	7.79E-04	0.0016
Naphthalene	2.89E-03	2.89E-03	0.0058
Nickel	1.02	1.02	2.0400
Phenol	2.07E-02	2.07E-02	0.0414
Phosphorus	2.56E-01	2.56E-01	0.5120
Polycyclic organic matter	7.69E-04	7.69E-04	0.0015
Selenium	4.52E-03	4.52E-03	0.0090
Terachloroethylene	4.69E-04	4.69E-04	0.0009
Toluene	4.64E-02	4.64E-02	0.0928
Vinyl acetate	4.39E-03	4.39E-03	0.0088
Xylenes	1.87E-03	1.87E-03	0.0037

*Includes H_2SO_4 mist.

Sources: TEC, 1999.
GE, 1998.
ECT, 1999.

Stack parameters for the natural gas-fired CTG/heat recovery steam generator (HRSG) units are provided in Table 2-7 and 2-8 for natural gas and distillate fuel oil firing, respectively.

Table 2-7. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	75	22.9	1,081	856	63.3	19.3	28.9	8.80
	59	75	22.9	1,117	876	60.5	18.4	28.9	8.80
	90	75	22.9	1,141	889	57.6	17.6	28.9	8.80
75	20	75	22.9	1,111	873	51.4	15.7	28.9	8.80
	59	75	22.9	1,.139	888	50.1	15.3	28.9	8.80
	90	75	22.9	1,166	903	48.3	14.7	28.9	8.80
50	20	75	22.9	1,160	900	43.5	13.3	28.9	8.80
	59	75	22.9	1,184	913	42.7	13.0	28.9	8.80
	90	75	22.9	1,200	922	41.4	12.6	28.9	8.80

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 1999.

Table 2-8. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	75	22.9	1,067	848	64.9	19.8	28.9	8.80
	59	75	22.9	1,098	865	62.4	19.0	28.9	8.80
	90	75	22.9	1,130	883	59.1	18.0	28.9	8.80
75	20	75	22.9	1,184	913	52.3	15.9	28.9	8.80
	59	75	22.9	1,195	919	50.9	15.5	28.9	8.80
	90	75	22.9	1,200	922	49.2	15.0	28.9	8.80
50	20	75	22.9	1,200	922	43.9	13.4	28.9	8.80
	59	75	22.9	1,200	922	43.3	13.2	28.9	8.80
	90	75	22.9	1,200	922	42.2	12.8	28.9	8.80

Note: K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

Sources: GE, 1998.
ECT, 1999.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

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. The Polk Power Station is located in southwestern Polk County approximately 17 miles south of the City of Lakeland. Polk County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs] and SO_2), unclassifiable/attainment (for CO and ozone), unclassifiable or better than national standards (for nitrogen dioxide [NO_2]), and not designated (for lead). Polk County is designated attainment (for ozone, SO_2, CO, and NO_2) and unclassifiable (for PM_{10} and lead) by Section 62-204.340, F.A.C.

3.2 NONATTAINMENT NSR APPLICABILITY

The Polk Power Station is located in Polk County. As noted previously, Polk County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the Project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The existing Polk Power Station is classified as a *major facility*. A modification to a major facility which has potential net emissions equal to or exceeding the significant emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Table 3-1. National and Florida Air Quality Standards

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2 (ppmv)	3-hour[1]		0.5	0.5
	24-hour[1]	0.14		0.1
	Annual[2]	0.030		0.02
PM_{10} ($\mu g/m^3$)	24-hour[3]	150	150	
	Annual[4]	50	50	
PM_{10} ($\mu g/m^3$)	24-hour[5]			150
	Annual[6]			50
$PM_{2.5}$ ($\mu g/m^3$)	24-hour[7]	65	65	
	Annual[8]	15	15	
CO (ppmv)	1-hour	35		35
	8-hour	9		9
Ozone (ppmv)	1-hour[9]	0.12	0.12	0.12
	8-hour[10]	0.08	0.08	
NO_2 (ppmv)	Annual	0.053	0.053	0.05
Lead ($\mu g/m^3$)	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

[1] Not to be exceeded more than once per calendar year.
[2] Arithmetic mean.
[3] Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[4] Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[5] Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.
[6] Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.
[7] Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[8] Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[9] Standard attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.
[10] Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.

Sources: 40 CFR 50.
Section 62-204.240, F.A.C.

The proposed two, new simple-cycle CTGs will have potential emissions in excess of the significant emission rate thresholds. Therefore, the project qualifies as a major modification to a major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Comparisons of estimated potential annual emission rates for the Project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, CO, PM, PM_{10}, SO_2, VOC, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Attachment D provides detailed emission rate estimates for the Project.

Table 3-2. Projected Emissions Compared to PSD Significant Emission Rates

Pollutant	Projected Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	581.0	40	Yes
CO	303.2	100	Yes
PM	66.2	25	Yes
PM_{10}	66.2	15	Yes
SO_2	126.4	40	Yes
Ozone/VOC	73.6	40	Yes
Lead	0.099	0.6	No
Mercury	0.0016	0.1	No
Total fluorides	0.45	3	No
H_2SO_4 mist	14.6	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not present	40	No
Municipal waste combustor metals (measured as PM)	Not present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 1999.

4.0 PSD NSR REQUIREMENTS

4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by the Project in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(42), F.A.C., BACT is "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

BACT is defined in terms of a numerical emissions limit. This numerical emissions limit can be based on the application of air pollution control equipment; specific production processes, methods, systems, or techniques; fuel cleaning; or combustion techniques. BACT limitations may not exceed any applicable federal new source performance standard (NSPS), national emission standard for hazardous air pollutants (NESHAP), or any other emission limitation established by state regulations.

BACT analyses must be conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of "Improving New Source Review (NSR) Implementation." Using the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank-ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable or is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those which exceed the PSD significant emission rate thresholds shown in Table 3-2).

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

Rule 62-212.400(2)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the proposed Project is discussed in Section 8.0.

4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(260), F.A.C., significant impact level, as presented in Table 4-2.

Ozone is one pollutant for which a source impact analysis is not normally required. Ozone is formed in the atmosphere as a result of complex photochemical reactions. Models for ozone generally are applied to entire urban areas.

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the 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 PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the

Table 4-1. PSD *De Minimis* Ambient Impact Levels

Averaging Time	Pollutant	Significance Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Hydrogen sulfide	0.2
NA	Ozone	100 tpy of VOC emissions

Source: Section 62-212.400, Table 212.400-3, F.A.C.

Table 4-2. Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	1
	24-Hour	5
	3-Hour	25
PM_{10}	Annual	1
	24-Hour	5
NO_2	Annual	1
CO	8-Hour	500
	1-Hour	2,000
Lead	Quarterly	0.03

Source: Rule 62-210.200(260), F.A.C.

area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated PSD increments for NO_2; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at February 8, 1988; new major sources or modifications constructed after this date will consume NO_2 increment.

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments which were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which include revised NAAQS for PM_{10} and new NAAQS for particulate matter less than or equal to 2.5 micrometers ($PM_{2.5}$), became effective on September 16, 1997. Due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for State permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 4-3.

Table 4-3. PSD Allowable Increments (µg/m^3)

Pollutant	Averaging Time	Class I	Class II	Class III
PM_{10}	Annual arithmetic mean	4	17	34
	24-Hour maximum*	8	30	60
SO_2	Annual arithmetic mean	2	20	40
	24-Hour maximum*	5	91	182
	3-Hour maximum*	25	512	700
NO_2	Annual arithmetic mean	2.5	25	50

*Maximum concentration not to be exceeded more than once per year at any one location.

Source: Section 62-204.260, F.A.C.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources that commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.

The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s) (i.e., allowed increment consumption):

- Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major source baseline date* means January 6, 1975, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2. *Minor source baseline date* means the earliest date after the trigger date on which the first complete application was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

The ambient impact analysis for the Project is provided in Sections 6.0 (Methodology) and 7.0 (Results).

4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

- A projection of the associated industrial, commercial, and residential growth that will occur in the area.
- An estimate of the air pollution emissions generated by the permanent associated growth.
- An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

The soils and vegetation analysis is typically conducted by comparing projected ambient concentrations for the pollutants of concern with applicable susceptibility data from the air pollution literature. For most types of soils and vegetation, ambient air concentrations of criteria pollutants below the NAAQS will not result in harmful effects. Sensitive vegetation and emissions of toxic air pollutants could necessitate a more extensive assessment of potential adverse effects on soils and vegetation.

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project.

Section 9.0 provides the additional impact analyses for the Project.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 4.1. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar projects.

Following the identification of available control technologies, the next step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the *EPA NSR Workshop Manual* (EPA, 1990a). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1996). Table 5-1 summarizes specific factors used in estimating capital and annual operating costs.

The fifth and final step is the selection of a BACT emission limitation corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Sales tax	0.06 × purchased equipment cost
Freight	0.05 × purchased equipment cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Source: EPA, 1996.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of NO_x, CO, PM/PM_{10}, SO_2, VOC, and H_2SO_4 mist for the Project exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM_{10}), products of incomplete combustion (CO and VOC), and acid gases (NO_x, SO_2, and H_2SO_4 mist), respectively.

5.2 FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAP (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 million British thermal units per hour (MMBtu/hr) based on the lower heating value (LHV) of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The Project CTGs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively. The proposed CTGs have no applicable NESHAP/maximum achievable control technology (MACT) requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, Stationary Sources—Emission Standards, F.A.C. Chapter 62-296, F.A.C., contains general emission standards for sources emitting VOCs and PM (Section 62-296.320, F.A.C.) which may be applicable to the Project. If deemed necessary by FDEP, vapor emission control devices must be employed during the handling of any VOC as required by Rule 62-296.320(1)(a), F.A.C. Visible emissions are limited to a maximum of 20-percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through 62-296.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTGs. Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment areas) and 62-296.700, F.A.C. (for PM nonattainment areas). Because the Project will be located in Polk County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart GG, Stationary Gas Turbines, is applicable to the Project CTGs. There are no applicable NESHAP requirements.

Tables 5-2 and 5-3 summarize applicable federal and state emission standards, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment D. BACT emission limitations proposed for the Project are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM_{10}

PM/PM_{10} emissions resulting from the combustion of natural gas are due to oxidation of ash and sulfur contained in the fuel. Due to their low ash and sulfur contents, natural gas and distillate fuel oil combustion generate inherently low PM/PM_{10} emissions.

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies used for controlling PM/PM_{10} include the following:

- Centrifugal collectors.
- Electrostatic precipitators (ESPs).
- Fabric filters or baghouses.
- Wet scrubbers.

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	$STD = 0.0075 \times (14.4/Y) + F$

where: STD = allowable NOx emissions (percent by volume at 15-percent O_2 and on a dry basis).

Y = manufacturer's rated heat rate in kilojoules per watt hour at manufacturer's rated load, or actual measured heat rate based on LHV of fuel as measured at actual peak load. Y cannot exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen per:

FBN = fuel bound nitrogen.

FBN (weight percent)	F (NO_x - volume percent)
N • 0.015	0
0.015 < N • 0.1	$0.04 \times N$
0.1 < N • 0.25	$0.004 + 0.0067 \times (N-0.1)$
N > 0.25	0.005

where: N = nitrogen content of fuel; percent by weight.

SO_2 = • 0.015 percent by volume at 15-percent O_2 and on a dry basis; or fuel sulfur content • 0.8 weight percent.

Source: 40 CFR 60, Subpart GG.

Table 5-3. Florida Emission Limitations

Pollutant	Emission Limitation
General Visible Emissions Standard Rule 62-296.320(4)(b)1., F.A.C.	
• Visible emissions	<20-percent opacity (averaged over a 6-minute period
General VOCs or Organic Solvents Standard Rule 62-296.320(1)(a), F.A.C.	
• VOC	No person shall store, pump, handle, process, load, unload, or use in any process or installation VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.

Source: Chapter 62-296, F.A.C.

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas combustion are typically less than 1.0 micron in size.

ESPs remove particles from a gas stream through the use of electrical forces. Discharge electrodes apply a negative charge to particles passing through a strong electrical field. These charged particles then migrate to a collecting electrode having an opposite, or positive, charge. Collected particles are removed from the collecting electrodes by periodic mechanical rapping of the electrodes. Collection efficiencies are typically 95 percent for particles smaller than 2.5 microns in size.

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet scrubbers remove PM from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drops for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTGs, none of the previously described control equipment have been applied to CTGs because exhaust gas PM concentrations are inherently low. CTGs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The Project CTGs will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM concentrations. The estimated maximum PM/PM_{10} exhaust concentration (including H_2SO_4 mist) from each CTG is approximately 0.004 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are shown in Tables 5-4 and 5-5. All determinations are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for CTGs, the use of good combustion practices and clean fuels is considered to be BACT. The Project CTGs will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTGs will be fired primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up

Table 5-4. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	7.0	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
08/98	Santa Rosa Energy Center	167	1,600	(8.2)	0.0051	Combustion design and clean fuels
08/98	FP&L Ft. Myers Plant Repowering	170	1,600	—	—	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-5. Florida BACT PM Emission Limitation Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
08/17/92	Florida Power Corp. Intercession City	93	1,144	15.0	(0.0131)	Combustion design and clean fuels
		186	2,032	17.0	(0.0084)	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,170	36.8	0.0472	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	371	10.0	0.0323	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	928	15.0	0.0162	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,850	17.0	(0.0092)	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,765	17.0	0.009	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	406	20.0	0.026	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	991	15.0	(0.0151)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		—	—	Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,660	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,236	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,846	44.8	(0.0243)	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

fuel source. Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTGs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-6 summarizes PM/PM_{10} BACT emission limits proposed for the Project CTGs.

5.4 BACT ANALYSIS FOR CO AND VOC

CO and VOC emissions results from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOCs will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO and VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO and VOC emission rates. Emissions of NO_x and CO/VOCs are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO and VOC emissions).

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOCs from gas turbines: combustion process design and oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTGs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to carbon dioxide (CO_2) and water at temperatures lower than would be

Table 5-6. Proposed PM/PM_{10} BACT Emission Limit

Emission Source	Proposed PM/PM_{10} BACT Emission Limit* (% Opacity)
GE PG7241 (FA) CTG (per CTG)	10

*Maximum rate for all operating scenarios.

Source: ECT, 1999.

necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for both CO and VOCs up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO and VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for combustion devices that are fired with fuels containing appreciable amounts of sulfur.

Technical Feasibility

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the Project CTGs. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOCs are provided in the following sections.

5.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing an appreciable amount of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs fired with natural gas and distillate fuel oil. Because CO and VOC emission rates from CTGs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements, i.e., well below the defined PSD significant impact levels for CO. The location of the Project (Polk County, Florida) is classified attainment for all criteria pollutants. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of CO emissions from the Project indicate maximum CO impacts, without oxidation catalyst, will be insignificant.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CTG due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for the Project CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.5 inch of water (H_2O). This pressure drop will result in a 0.3-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 2,601,720 kilowatt-hours (kwh) (8,877 million British thermal units [MMBtu]) per year at baseload (165 MW) operation and 5,256 hr/yr operation per CTG. This energy penalty is equivalent to the use of 16.9 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for both CTGs. The lost power generation energy penalty, based on a power cost of $0.040/kwh, is $208,138 per year for both CTGs.

5.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-7. Tables 5-8 and 5-9 summarize specific capital and annual operating costs for the oxidation catalyst control system.

Base case CTG exhaust CO concentrations for natural gas and fuel oil firing are 15 and 33 ppmvd, respectively. Control efficiency for the CO oxidation catalyst system, consistent with efficiencies typically required for oxidation catalyst systems located in nonattainment areas, is assumed to be 90 percent. Base case and controlled CO emission rates are summarized in Table 5-10.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $3,652 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO and VOC emissions is not considered economically feasible. Table 5-10 summarizes results of the oxidation catalyst economic analysis.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO and VOCs from CTGs is typically required only for facilities located in CO and/or ozone nonattainment areas. FDEP natural gas-fired CTG CO BACT determinations for the past 5 years range from 15 to 30 ppmvd with an average CO limit of 26 ppmvd. Of the 13 recent FDEP CO BACT determinations for natural gas-fired CTGs, 12 determinations established a limit of 20 ppmvd or higher. A summary of FDEP CO BACT determinations for natural gas- and distillate fuel oil-fired combustion turbines for the previous 5 years is provided in Tables 5-11 and 5-12. A summary of FDEP VOC BACT determinations for natural gas- and distillate fuel oil-fired combustion turbines for the previous 5 years is provided in Tables 5-13 and 5-14.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs fired with natural gas. Because CO and VOC emission rates from CTGs are inherently low, further reductions

Table 5-7. Economic Cost Factors

Factor	Units	Value
Interest rate	%	9.55
Control system life	Years	15
Catalyst life	Years	
Oxidation		5*
SCR		5*
Electricity cost	$/kwh	0.040
Aqueous NH_3 cost	$/ton	320
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

*Control system vendor guarantee is 3 years.

Sources: TEC, 1999.
ECT, 1999.

Table 5-8. Capital Costs for Oxidation Catalyst System

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Purchased equipment	1,075,000	A
Sales tax	64,500	0.06 × A
Freight	53,750	0.05 × A
Subtotal Purchased Equipment	**$1,193,250**	**B**
Installation		
Foundations and supports	95,460	0.08 × B
Handling and erection	167,055	0.14 × B
Electrical	47,730	0.04 × B
Piping	23,865	0.02 × B
Insulation for ductwork	11,933	0.01 × B
Painting	11,933	0.01 × B
Subtotal Installation Cost	**$357,975**	
Subtotal Direct Costs	**$1,551,225**	
<u>Indirect Costs</u>		
Engineering	119,325	0.10 × B
Construction and field expenses	59,663	0.05 × B
Contractor fees	119,325	0.10 × B
Start-up	23,865	0.02 × B
Performance test	11,933	0.01 × B
Contingency	35,798	0.03 × B
Subtotal Indirect Costs	**$369,908**	
TOTAL CAPITAL INVESTMENT	**$1,921,133** (TCI)	

Sources: Engelhard, 1999
ECT, 1999

Table 5-9. Annual Operating Costs for Oxidation Catalyst System

Item	Dollars		OAQPS Factor
Direct Costs			
Catalyst costs			
Replacement (materials and labor)	930,000		
Credit for used catalyst	(127,500)		
Subtotal Catalyst Costs	**$802,500**		
Annualized Catalyst Costs	**$209,269**		
Energy penalties			
Turbine backpressure	104,069		
Subtotal Direct Costs	**$313,338**	(TDC)	
Indirect Costs			
Administrative charges	38,423		0.02 × TCI
Property taxes	19,211		0.01 × TCI
Insurance	19,211		0.01 × TCI
Capital recovery	125,249		
Subtotal Indirect Costs	**$202,094**		
TOTAL ANNUAL COST	**$515,433**		

Sources: Engelhard, 1999
TEC, 1999.
ECT, 1999.

Table 5-10. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts				Energy Impacts	
	Environmental Impacts								
	Emission Rates		Emission Reduction	Installed Capital Cost	Total Annualized Cost	Cost Effectiveness Over Baseline	Increase Over Baseline	Toxic Impact	Adverse Environmental Impact
Control Option	lb/hr	tpy	(tpy)	($)	($/yr)	($/ton)	(MMBtu/yr)	(Y/N)	(Y/N)
Oxidation catalyst	11.5	30.2	272.8	3,842,266	996,176	3,652	14.1	Y	Y
Baseline	115.3	303.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) CTGs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 876 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 1999.

Table 5-11. Florida BACT CO Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
08/99	Santa Rosa Energy Center	167	9	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-12. Florida BACT CO Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	63	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	30	Good combustion
02/21/94	Polk Power Partners	84	35	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	40	Good combustion
07/20/94	Pasco Cogen, Limited	42	18	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	25	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-13. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0017	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
03/07/95	Orange Cogeneration, L.P.	39	10		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	4		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	7		Good combustion
08/99	Santa Rosa Energy Center	167	1.4		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-14. Florida BACT VOC Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit ppmvd	VOC Emission Limit lb/MmBtu	Control Technology
02/21/94	Polk Power Partners	84	25		Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260		0.0128	Good combustion
07/20/94	Pasco Cogen, Limited	42	28		Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20		Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	10		Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	10		Good combustion

Note: ( ) = calculated values.

Source: FDEP, 1998.

through the use of oxidation catalysts will result in only minor improvement in air quality (i.e., well below the defined PSD significant impact levels for CO).

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. These control techniques have been considered by FDEP to represent BACT for CO and VOCs for all CTG projects permitted within the past 5 years. At baseload operation with natural gas firing, the maximum CO exhaust concentrations from the CTGs will be 15 ppmvd and 48.0 lb/hr. At baseload operation with distillate fuel oil firing, the maximum CO exhaust concentrations from the CTGs will be 33 ppmvd and 106.0 lb/hr. At baseload operation for both natural gas and distillate fuel oil firing, the maximum VOC exhaust concentrations from the CTGs will be 7 ppmvd and 15.0 lb/hr. Table 5-15 summarizes the CO and VOC BACT emission limits proposed for the Project.

5.5 BACT ANALYSIS FOR NO_X

NO_x emissions from combustion sources consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO_x and prompt NO_x) and conversion of chemically bound fuel nitrogen (fuel NO_x). Essentially all CTG NO_x emissions originate as nitric oxide (NO). NO generated by the CTG combustion process is subsequently further oxidized in the CTG exhaust system or in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed near the combustion flame front from the oxidation of intermediate combustion products such as hydrogen cyanide (HCN), nitrogen (N), and NH. Prompt NO_x comprises a small portion of total NO_x in conventional near-stoichiometric CTG combustors but increases under fuel-lean conditions. Prompt NO_x, therefore, is an important consideration with respect to dry low-NO_x combustors that use lean fuel mixtures. Fuel NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound

Table 5-15. Proposed CO and VOC BACT Emission Limits

Emission Source	lb/hr	ppmvd
<u>Proposed CO BACT Emission Limits</u>*†		
GE PG7241 (FA) CTG (Natural Gas-Fired, Per CTG)	51.0	15
GE PG7241 (FA) CTG (Distillate Fuel Oil-Fired, Per CTG)	113.0	33
<u>Proposed VOC BACT Emission Limits</u>*†		
GE PG7241 (FA) CTG (Natural Gas-Fired, Per CTG)	15.0	7
GE PG7241 (FA) CTG (Distillate Fuel Oil-Fired, Per CTG)	15.0	7

*Maximum rates for all operating scenarios.
†24-hour block average.

Sources: GE, 1998.
ECT, 1999.

nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-2). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from CTGs include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

<u>Combustion Process Modifications</u>:

- Water or steam injection and standard combustor design.
- Water or steam injection and advanced combustor design.
- Dry low-NOx combustor design.

<u>Postcombustion Exhaust Gas Treatment Systems</u>:

- Selective non-catalytic reduction (SNCR).
- Non-selective catalytic reduction (NSCR).
- SCR.
- SCONOx™

A description of each of the listed control technologies is provided in the following sections.

<u>Water or Steam Injection and Standard Combustor Design</u>

Injection of water or steam into the primary combustion zone of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO_x.

The maximum amount of steam or water that can be injected depends on the CTG combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water-to-fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely effect safe, efficient, and reliable operation of the turbine.

The use of water or steam injection and standard turbine combustor design can generally achieve NO_x exhaust concentrations of 42 and 65 ppmvd for gas and oil firing, respectively.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described previously for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO_x and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil firing, respectively.

Dry Low-NO_x Combustor Design

A number of turbine vendors have recently developed dry low-NO_x combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperature are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical dry low-NO_x combustor incorporates fuel staging using several operating modes as follows:

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.
- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 75 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.
- Secondary Mode (Transfer to Premix)—At 70-percent load, all fuel is supplied to second stage.
- Premix Mode—Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 40 percent of baseline due to flame stability considerations. During oil firing, wet injection is employed to control NO_x emissions.

In addition to lean premixed combustion, CTG dry low-NO_x combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All CTGs cool the high-temperature CTG exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the CTG turbine. By adding additional dilution air, the hot CTG exhaust gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the CTG combustion gases are at a higher temperature for a shorter period of time.

Current dry low-NO_x combustor technology can typically achieve a NO_x exhaust concentration of 15 ppmvd or less using natural gas fuel.

Selective Non-Catalytic Reduction

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO_x in the exhaust gas stream with injected ammonia (NH_3) or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either NH_3 (Thermal DeNO_x) or urea (NO_xOUT) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO_x process are as follows:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6\,H_2O \qquad (1)$$

$$4\,NH_3 + 5\,O_2 \rightarrow 4NO + 6\,H_2O \qquad (2)$$

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process utilizes a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3 percent O_2) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

In contrast to SNCR, SCR reduces NO_x emissions by reacting NH_3 with exhaust gas NO_x to yield nitrogen and water vapor in the presence of a catalyst. NH_3 is injected upstream of the catalyst bed where the following primary reactions take place:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \qquad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (4)$$

The catalyst serves to lower the activation energy of these reactions, which allows the NO_x conversions to take place at a lower temperature (i.e., in the range of 600 to 750°F). Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), NH_3/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions.

As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Specially formulated high temperature zeolite catalysts have been recently developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. The exhaust temperature range for the GE 7FA simple cycle unit is 1,067 to 1,200°F. Accordingly, the CTG exhaust temperature would need to be reduced to an acceptable level prior to treatment by a hot SCR control system. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Due to the potential for chemical poisoning with fuels other than natural gas, application of SCR to CTGs has been primarily limited to natural gas-fired units.

$SCONO_x$™

$SCONO_x$™ 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.

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:

$$CO + \tfrac{1}{2} O_2 \rightarrow CO_2 \quad (1)$$

$$NO + \tfrac{1}{2} O_2 \rightarrow NO_2 \quad (2)$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (3)$$

CO_2 produced by reaction (1) and (2) is released to the atmosphere as part of the CTG/HRSG exhaust as 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 CTG/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 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:

$$CH_4 + \tfrac{1}{2}O_2 + 1.88\,N_2 \rightarrow CO + 2\,H_2 + 1.88\,N_2 \qquad (5)$$

$$CO + 2\,H_2 + H_2O + 1.88\,N2_2 \rightarrow CO_2 + 3\,H_2 + 1.88\,N_2 \qquad (6)$$

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, which 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 SCOSO$_x$™ catalyst, either H_2SO_4 or SO_2 is released to the atmosphere as part of the CTG/HRSG exhaust gas stream. The absorption portion of the SCOSO$_x$™ process is proprietary. SCOSO$_x$™ oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \qquad (7)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \qquad (8)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \qquad (9)$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O \qquad (10)$$

Utility materials need 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, CC power plant located in Los Angeles. This power plant, owned by GLET partner Sunlaw Energy Corporation, uses a GE LM2500 turbine 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 parts per million by volume (ppmv) resulting in an approximate 85-percent NO$_x$ removal efficiency.

Technical Feasibility

All of the combustion process modification technologies mentioned (water or steam injection and standard combustor design, water or steam injection and advanced combustor, and dry low-NO$_x$ combustor design) would be feasible for the Project CTGs. Of the postcombustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CT exhaust gas streams (approximately 1,100°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent O_2) environment. Due to high excess air rates, the O_2 content of combustion turbine exhaust gases is typically 13 percent. The SCONO$_x$™ control technology is not technically feasible because the temperature required for this technology (between 300 to 700°F) is well below the 1,100°F typically occurring for simple-cycle CTG exhaust gas streams. In addition, SCONO$_x$™ control technology has not been commercially demonstrated on large CTGs. The CTGs planned for the Project, GE PG7241 (FA) units, each have a nominal generation capacity of 165 MW. Accordingly, the Project CTGs are approximately 6.5 times larger than the nominal 25-MW GE LM2500 used at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the SCONO$_x$™ technology are unknown. Additional concerns with the SCONO$_x$™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, and the relatively brief (approximately 18 months) operating history of the technology.

For natural gas firing, use of advanced dry low-NO_x combustor technology will achieve NO_x emission rates comparable to or less than wet injection based on CTG vendor data. Accordingly, the BACT analysis for NO_x for the Project CTGs was confined to advanced dry low-NO_x combustors (natural gas firing), water injection (distillate fuel oil firing), and the application of post-combustion hot SCR control technologies. Hot SCR is considered potentially feasible with the addition of CTG exhaust stream cooling. However, there are currently no such installations on large, simple-cycle CTGs. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

The use of advanced dry low-NO_x combustor technology will not have a significant adverse impact on CTG heat rate.

The installation of hot SCR technology would cause an increase in back pressure on the CTGs due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. Energy penalty due to CTG back pressure is projected to be 5,203,440 kwh per year (17,755 MMBtu/yr) at baseload operation per CTG. The total SCR energy penalty (for both CTGs) of 35,510 MMBtu/yr is equivalent to the use of 33.8 million ft^3 of natural gas annually based on a gas heating value of 1,050 Btu/ft^3. The lost power generation penalty due to turbine back pressure, based on a power cost of $0.040/kwh, is $416,275 per year for both CTGs.

There are no significant adverse environmental effects due to the use of advanced dry low-NO_x combustor technology. In contrast, application of hot SCR technology would result in the following adverse environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 100.8 tpy (at baseload and 59• F ambient temperature) for a SCR design NH_3 slippage rate of 5 ppmvd for both CTGs. However, ammonia slip can increase significantly during start-ups, upsets or failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of NH_3 is 20 ppmv, releases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; total PM emissions would increase by approximately 50 percent.
- A public risk due to potential leaks from the storage of large quantities of NH_3; NH_3 has been designated an "Extremely Hazardous Substance" under the federal Superfund Amendment and Reauthorization Act Title III regulations.
- Disposal of spent catalyst that may be considered hazardous due to heavy metal contamination; vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery

Act Regulations 40 CFR 261.30. As a potential hazardous waste, spent catalyst may have to be transported and disposed in a hazardous waste landfill. In addition, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced dry low-NO_x combustor technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 10.5 and 42 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 14.0 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired CTGs equipped with dry low-NO_x combustor technology and SCR controls. As supplied by GE, the PG7241 (FA) unit is equipped with duel-fuel low-NO_x combustors. GE offer no other option with respect to combustor type or design.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-7. Emission reductions were calculated assuming baseload operation for 4,380 and 876 hr/yr (for natural gas and distillate fuel oil firing, respectively) at an annual average ambient temperature of 59°F. Tables 5-16 and 5-17 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to the Project CTGs was determined to be $9,717 per ton of NO_x removed. This control cost is considered economically unreasonable. Table 5-18 summarizes results of the NO_x BACT analysis.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

FDEP natural gas-fired CTG NO_x BACT determinations for the past 5 years range from 12 to 25 ppmvd at 15-percent O_2 with an average NO_x limit of 15 ppmvd at 15-percent O_2. Of the ten most recent FDEP NO_x BACT determinations for CTGs, seven determinations established a limit

Table 5-16. Capital Costs for SCR System

Item	Dollars		OAQPS Factor
Direct Costs			
Purchased equipment	4,035,000	(A)	
Sales tax	242,100		0.06 × A
Freight	201,750		0.05 × A
Subtotal Purchase Equipment	**$4,478,850**		B
Installation			
Foundations and supports	358,308		0.08 × B
Handling and erection	627,039		0.14 × B
Electrical	179,154		0.04 × B
Piping	89,577		0.02 × B
Insulation for ductwork	44,789		0.01 × B
Painting	44,789		0.01 × B
Subtotal Installation Cost	**$1,343,655**		
Subtotal Direct Costs	**$5,822,505**		
Indirect Costs			
Engineering	447,885		0.10 × B
Construction and field expenses	223,943		0.05 × B
Contractor fees	447,885		0.10 × B
Start-up	89,577		0.02 × B
Performance test	44,789		0.01 × B
Contingency	134,366		0.15 × B
Subtotal Indirect Costs	**$1,388,444**		
TOTAL CAPITAL INVESTMENT	**$7,210,949**	(TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-17. Annual Operating Costs for SCR System

Item	Dollars		OAQPS Factor
<u>Direct Costs</u>			
Labor and material costs			
Operator	7,227	(A)	
Supervisor	1,084		0.15 × A
Maintenance			
Labor	7,227	(B)	
Materials	7,227		1.00 × B
Subtotal Labor, Material, and Maintenance Costs	**$22,765**	(C)	
Catalyst costs			
Replacement (materials and labor)	$2,088,000		
Annualized Catalyst Costs	**$544,491**		
Raw materials and utilities			
Electricity	17,722		
Aqueous NH_3	119,092		
Subtotal Raw Materials and Utilities	**$136,864**		
Energy penalties			
Turbine backpressure	208,138		
Subtotal Direct Costs	**$912,209**	(TDC)	
<u>Indirect Costs</u>			
Overhead	13,659		0.60 × C
Administrative charges	144,219		0.02 × TCI
Property taxes	72,110		0.01 × TCI
Insurance	72,110		0.01 × TCI
Capital recovery	667,855		
Subtotal Indirect Costs	**$969,952**		
TOTAL ANNUAL COST	**$1,882,161**		

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-18. Summary of NO_x BACT Analysis

	Emission Impacts			Economic Impacts				Energy Impacts	
	Environmental Impacts								
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	Adverse Environmental Impact (Y/N)
SCR	36.8	193.4	387.4	14,421,898	3,764,322	9,717	35,510	Y	Y
Baseline	110.5	580.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) CTGs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 876 hr/yr oil-fired.

Sources: GE, 1998.
ECT, 1999.

of 15 ppmvd or higher. Tables 5-19 and 5-20 provides a summary of FDEP NO_x BACT determinations for natural gas- and distillate fuel oil-fired CTGs for the previous 5 years.

At baseload operation with natural gas firing, maximum NO_x exhaust concentrations from the CTGs will be 10.5 ppmvd and 73.5 lb/hr based on the application of dry low-NO_x combustors. At baseload operation with distillate fuel oil firing, maximum NO_x exhaust concentrations from the CTGs will be 42 ppmvd and 338.0 lb/hr based on the use of wet injection. Table 5-21 summarizes the NO_x BACT emission limits proposed for the Project. NO_x emission rates proposed as BACT for the Project CTGs are consistent with prior FDEP BACT determinations.

As provided in Attachment B, GE guarantees the 7FA CTG will achieve a NO_x exhaust concentration of 9 ppmvd, corrected to 15-percent O_2 only during the contract performance test with steady-state load of 50 to 100 percent, which must be completed within the first 100 fired hours of operation and only under operation as specified in the GE testing protocols. However, this guaranteed performance does not cover long-term performance of the unit, nor does it consider that the Polk Power Station simple-cycle CTGs will operate with frequent start-ups and shutdowns. For this reason, a BACT NO_x limit of 10.5 ppmvd is requested as a more realistic, long-term achievable limitation.

5.6 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

5.6.1 POTENTIAL CONTROL TECHNOLOGIES

Technologies employed to control SO_2 and H_2SO_4 mist emissions from combustion sources consist of fuel treatment and postcombustion add-on controls (i.e., flue gas desulfurization (FGD) systems).

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas and fuel oils containing sulfur compounds (e.g., H_2SO_4), a variety of technologies are available to remove these sulfur compounds to acceptable levels. Desulfurization of natural gas and fuel oils are performed by the fuel supplier prior to distribution by pipeline.

Table 5-19. Florida BACT NO_x Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_x Emission Limit (ppmvd)	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	15	Dry low-NO_x combustors
08/17/92	Florida Power Corp. University of Florida	43	25	Steam injection
12/17/92	Auburndale Power Partners	104	25	Steam injection
			15	Steam injection
04/09/93	Kissimmee Utility Authority	40	25	Water injection
			15	Dry low-NO_x combustors
04/09/93	Kissimmee Utility Authority	80	25	Water injection
			15	Dry low-NO_x combustors
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	25	Dry low-NO_x combustors
		184	15	Dry low-NO_x combustors
02/21/94	Polk Power Partners	84	25	Dry low-NO_x combustors
			15	Dry low-NO_x combustors
02/24/94	Tampa Electric Company Polk Power Station	260	25	Nitrogen diluent injection
07/20/94	Pasco Cogen, Limited	42	25	Wet injection
03/07/95	Orange Cogeneration, L.P.	39	15	Dry low-NO_x combustors
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	15	Dry low-NO_x combustors
06/01/95	Panda-Kathleen	75	15	Dry low-NO_x combustors
09/28/95	City of Key West (relocated unit)	23	75	Water injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	15	Dry low-NO_x combustors
05/98	City of Tallahassee Purdom Unit 8	160	12	Dry low-NO_x combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Dry low-NO_x combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	9	Dry low-NO_x combustors or SCR (effective 05/01/2002)
09/28/98	Florida Power Corp. Hines Energy Complex	165	12	Dry low-NO_x combustors and/or SCR
08/99	Santa Rosa Energy Center	167	9	Dry low-NO_x combustors

Source: FDEP, 1998.

Table 5-20. Florida BACT NO_x Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_x Emission Limit (ppmvd)	Control Technology
08/17/92	Florida Power Corp. University of Florida	43	42	Steam injection
08/17/92	Florida Power Corp. Intercession City	93	42	Wet injection
08/17/92	Florida Power Corp. Intercession City	186	42	Steam injection
12/17/92	Auburndale Power Partners	104	42	Steam injection
04/09/93	Kissimmee Utility Authority	40	42	Water injection
04/09/93	Kissimmee Utility Authority	80	42	Water injection
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	42	Wet injection
02/21/94	Polk Power Partners	84	42	Wet injection
02/24/94	Tampa Electric Company Polk Power Station	260	42	Wet injection
07/20/94	Pasco Cogen, Limited	42	42	Wet injection
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	42	Wet injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	—	—
05/98	City of Tallahassee Purdom Unit 8	160	42	Water or steam injection
07/10/98	City of Lakeland McIntosh Unit 5	250	42	Water injection
09/28/98	Florida Power Corp. Hines Energy Complex	165	42	Water injection

Source: FDEP, 1998.

Table 5-21. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits*†	
	lb/hr	ppmvd**
GE PG 241 (FA) CTG (Natural Gas firing, Per CTG)	73.5	10.5
GE PG 241 (FA) CTG (Distillate Fuel Oil firing, Per CTG)	338.0	42

* Maximum rates for all operating scenarios
† 24-hour block average.
**Corrected to 15-percent O_2.

Sources: GE, 1998.
ECT, 1999.

Flue Gas Desulfurization

FGD systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using either a wet- or dry-contact system. FGD wet scrubbers typically employ sodium, calcium, or dual-alkali reagents using packed or spray towers. Wet FGD systems will generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream. The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas and fuel oils to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas and distillate fuel oil sulfur contents have already been reduced to very low levels.

There have been no applications of FGD technology to CTGs because low sulfur fuels are typically used. The Project CTGs will be fired with natural gas and distillate fuel oil. The sulfur content of natural gas, the primary fuel source, is more than 100 times lower than the fuels (e.g., coal) employed in boilers using FGD systems. In addition, CTGs operate with a significant amount of excess air that generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of an FGD system to a CTG exhaust stream will result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology is not considered to be technically feasible for CTGs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H_2SO_4 mist emissions is not technically feasible due to the very low CTG H_2SO_4 mist exhaust concentrations. For example, the project CTGs will have an H_2SO_4 mist exhaust concentration of 0.00013 grains per actual cubic foot (gr/acf) at 100-percent load, 20°F, and distillate fuel oil firing operating conditions.

5.6.2 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuel is considered to represent BACT for the Project CTGs. Natural gas used at the Project will contain no more than 2.0 gr S/100 scf. Distillate fuel oil used for the new CTGs as a back-up fuel source will contain no more than 0.05 wt%S. Emissions of H_2SO_4 mist were estimated based on a 7.5-percent conversion rate of SO_2 to H_2SO_4 mist. During natural gas firing, SO_2 and H_2SO_4 mist BACT emission limits proposed for the Project CTGs are 9.8 and 1.1 lb/hr, respectively. During distillate fuel oil firing, SO_2 and H_2SO_4 mist BACT emission limits proposed for the Project CTGs are 104.1 and 12.0 lb/hr, respectively. The proposed limits are based on the use of natural gas containing no more than 2.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S. Table 5-22 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the Project.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-23 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-24 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-22. Proposed SO_2 and H_2SO_4 Mist BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits* lb/hr	Fuel Sulfur Content (gr S/100 scf) (wt%S)
GE PG7241 (FA) CTG (Natural Gas firing, Per CTG)			
	SO_2	9.8	(≤2.0)
	H_2SO_4 mist	1.1	(≤2.0)
GE PG7241 (FA) CTG (Distillate Fuel Oil firing, Per CTG)			
	SO_2	104.1	[≤0.05]
	H_2SO_4 mist	12.0	[≤0.05]

*Maximum rates for all operating scenarios.

Sources: GE, 1998.
ECT, 1999.

Table 5-23. Summary of BACT Control Technologies

Pollutant	Control Technology
GE PG7241 (FA) CTGs	
PM/PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil.
	• Efficient and complete combustion.
CO and VOCs	• Efficient and complete combustion.
NO_x	• Use of advanced dry low-NO_x burners (natural gas firing).
	• Use of wet injection (distillate fuel oil firing).
SO_2/H_2SO_4 mist	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil.

Source: ECT, 1999.

Table 5-24. Summary of Proposed BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits* ppmvd	lb/hr
GE PG7241 (FA) CTG (Natural Gas firing, Per CTG)			
	PM/PM_{10}	10-percent opacity	
	CO	15†	51.0†
	NO_x	10.5†**	73.5†
	VOC	7†	15.0†
	SO_2 (fuel ≤2.0 gr S/100 scf)	N/A	9.8
	H_2SO_4 (fuel ≤2.0 gr S/100 scf)	N/A	1.1
GE PG7241 (FA) CTG (Distillate Fuel Firing, Per CTG)			
	PM/PM_{10}	10-percent opacity	
	CO	33†	113.0†
	NO_x	42†**	338.0†
	VOC	7†	15.0†
	SO_2 (fuel ≤0.05 wt % S)	N/A	104.1
	H_2SO_4 (fuel ≤0.05 wt % S)	N/A	12.0

* Maximum rates for all operating scenarios.
† 24-hour block average.
**Corrected to 15 percent O_2.

Sources: GE, 1998.
ECT, 1999.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the Project will have the potential to emit 581.0 tpy NO_x, 303.2 tpy of CO, 66.2 tpy of PM/PM_{10}, 126.4 tpy of SO_2, 73.6 tpy of VOCs, and 14.6 tpy of H_2SO_4 mist. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the Project and the PSD significant emission rate thresholds. As shown in this table, potential emissions of NO_x, CO, PM, PM_{10}, SO_2, VOC, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400 (5) (d), F.A.C.

The ambient impact analysis addresses PM, PM_{10}, SO_2, NO_x, and CO. There are no applicable PSD increments or AAQS for H_2SO_4 mist. Because VOCs contribute to the formation of ground-level ozone and because ozone modeling is conducted on a regional scale, no modeling of VOC emissions resulting from the Project was conducted.

6.3 MODEL SELECTION AND USE

For this study, air quality models were applied at two levels. The first, or screening, level provided conservative estimates of impacts from the cogeneration unit. The purposes of the screening modeling were to:

- Eliminate the need for more sophisticated analysis in situations with low predicted impacts and no threat to any standard.
- Provide information to guide the more rigorous refined analysis, including the operating mode (load and ambient temperature), which caused the highest ambient impact for each criteria pollutant.

The second, or refined, level encompassed a more detailed treatment of atmospheric processes. Refined modeling required more detailed and precise input data, but is presumed to have provided more accurate estimates of source impacts.

6.3.1 SCREENING MODELS

For screening purposes, the SCREEN3 model, Version 96043, is recommended and was used in this analysis. SCREEN3 is a simple model that calculates 1-hour average concentrations over a range of predefined worst-case meteorological conditions. SCREEN3 is appropriate for use in situations where building wake downwash is or is not a concern. SCREEN3 also includes algorithms for analyzing concentrations on simple and complex terrain.

The proposed CTGs units may operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and fuel type (i.e., natural gas or distillate fuel oil). Plume dispersion and, therefore, ground-level impacts will be affected by these different operating scenarios since emission rates, exit temperatures, and exhaust gas velocities will change. Each of the operating scenarios was evaluated for each pollutant of concern to identify the scenario that caused the highest impact. These worst-case operating scenarios were then subsequently evaluated using the refined Industrial Source Complex (ISC3) dispersion model. The two CTG stacks were collocated for screening modeling purposes since: (1) the two point sources will emit the same pollutant(s), (2) they both will have identical stack heights, volumetric flow rates, and stack gas exit temperatures, and (3) the stacks are situated relatively close to each other. A nominal emission rate of 10.0 grams per second (g/s) was used for all SCREEN3 model runs. The SCREEN3 model results were then adjusted to reflect maximum emission rates for each operating case (i.e., model results were multiplied by the ratio of maximum emission rates [in g/s] to 10.0 g/s). Screening modeling results are summarized in Section 7.0, Tables 7-1 through 7-5. These Tables show, for each operating scenario and pollutant evaluated, the SCREEN3 unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted SCREEN3 1-hour average maximum impact.

6.3.2 REFINED MODELS

The most recent regulatory version of the ISC3 models (EPA, 1997) is recommended and was used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISC3 short-term (ISCST3) (Version 98356) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's *Guideline for Air Quality Models* (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in addition to short-term averages, by using the ANNUAL parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.3.3 NO_2 AMBIENT IMPACT ANALYSIS

For annual NO_2 impacts, the tiered screening approach described in the GAQM, Section 6.2.3 was used. Tier 1 of this screening procedure assumes complete conversion of NO_x to NO_2. Tier 2 applies an empirically derived NO_2/NO_x ratio of 0.75 to the Tier 1 results.

6.4 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban since dispersion rates differ between these two classifications. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing, and the other is based on population density. The land use typing method uses the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban, while the agricultural areas are considered rural. However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character. In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Based on this analysis, more than 50 percent of the land use surrounding the plant was determined to be rural under the Auer land use classification technique. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

6.5 TERRAIN CONSIDERATION

The GAQM defines *flat terrain* as terrain equal to the elevation of the stack base, *simple terrain* as terrain lower than the height of the stack top, and *complex terrain* as terrain above the height of the plume center line (for screening modeling, complex terrain is terrain above the height of the stack top). Terrain above the height of the stack top but below the height of the plume center line is defined as *intermediate terrain.*

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the Polk Power Station (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the CTG stack base for modeling purposes).

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

The CAA Amendments of 1990 require the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds good engineering practice (GEP) or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (40 CFR 51). GEP stack height is defined as the highest of 65 meters or a height established by applying the formula:

$$Hg = H + 1.5\,L$$

where: Hg = GEP stack height.
H = height of the structure or nearby structure.
L = lesser dimension (height or projected width) of the nearby structure.

Nearby is defined as a distance up to five times the lesser of the height or width dimension of a structure or terrain feature, but not greater than 800 meters. While GEP stack height regulations require stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for the CTG units (75 feet [ft]) is less than the *de minimis* GEP height of 65 meters (213 ft), and, therefore, complies with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.
- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in the previous two items are satisfied (a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

For the ambient impact analysis, the complex downwash analysis described previously was performed using the current version of EPA's Building Profile Input Program (BPIP) (Version 95086). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. Table 6-1 provides dimensions of the building/structures evaluated for wake effects; the locations of these buildings/structures were previously provided on Figure 2-2. BPIP output consists of an array of 36 direction-specific (10 to 360 degrees [°]) building heights and projected building widths for each stack suitable for use as input to the ISCST3 model.

6.7 RECEPTOR GRIDS

Receptors were placed at locations considered to be *ambient air*, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." Section 2.0 provided a plot plan showing the site fence lines (see Figure 2-2). As shown in Figure 2-2, the entire perimeter of the plant site will be fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

Consistent with GAQM recommendations, the ambient impact analysis used the following receptor grids:

- Fence line receptors—Receptors placed on the site fence line at 10° spacing radials.
- Polar receptor rings (36 receptors at 10° spacing radials) at distances of 2,000, 2,500, 3,000, 3,500, 4,000, 5,000, 6,000, 7,000, 8,000, 9,000, 10,000, 12,500, 15,000, 17,500, 20,000, 22,500, 25,000, 27,500, 30,000, 32,500, 35,000, 40,000, 45,000, and 50,000 meters from the grid center.

This receptor grid is consistent with the grid employed in the modeling conducted for the original Polk Power Station project.

Figure 6-1 illustrates a graphical representation of the receptor grids (out to a distance of 5 km). A depiction of the receptor grids (from 5 to 50 km) is shown in Figure 6-2.

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
7F HRSG	13.1	40.0	27.4
Gasifier structure	19.2	18.3	91.4
Syngas cooling wings (2)	7.6	46.3	27.4
Air separation unit cold box	--	7.0*	50.3
Coal grinding structure	7.6	15.2	27.4
H_2SO_4 plant absorbers (2) and dryer (1)	--	2.4*	18.3
H_2SO_4 plant gas cooling tower	--	2.4*	21.3
Acid gas removal stripper	--	3.0*	30.5
Water wash column	--	3.0*	24.4
Acid gas removal absorber	--	3.0*	30.5
Coal storage silos (2)	--	18.0*	60.0
Hot gas cleanup unit	15.8	19.8	85.0
Oil storage tanks (3)	--	30.5	17.4

*Diameter

Sources: Texaco, 1992.
Bechtel, 1994.
ECT, 1999.

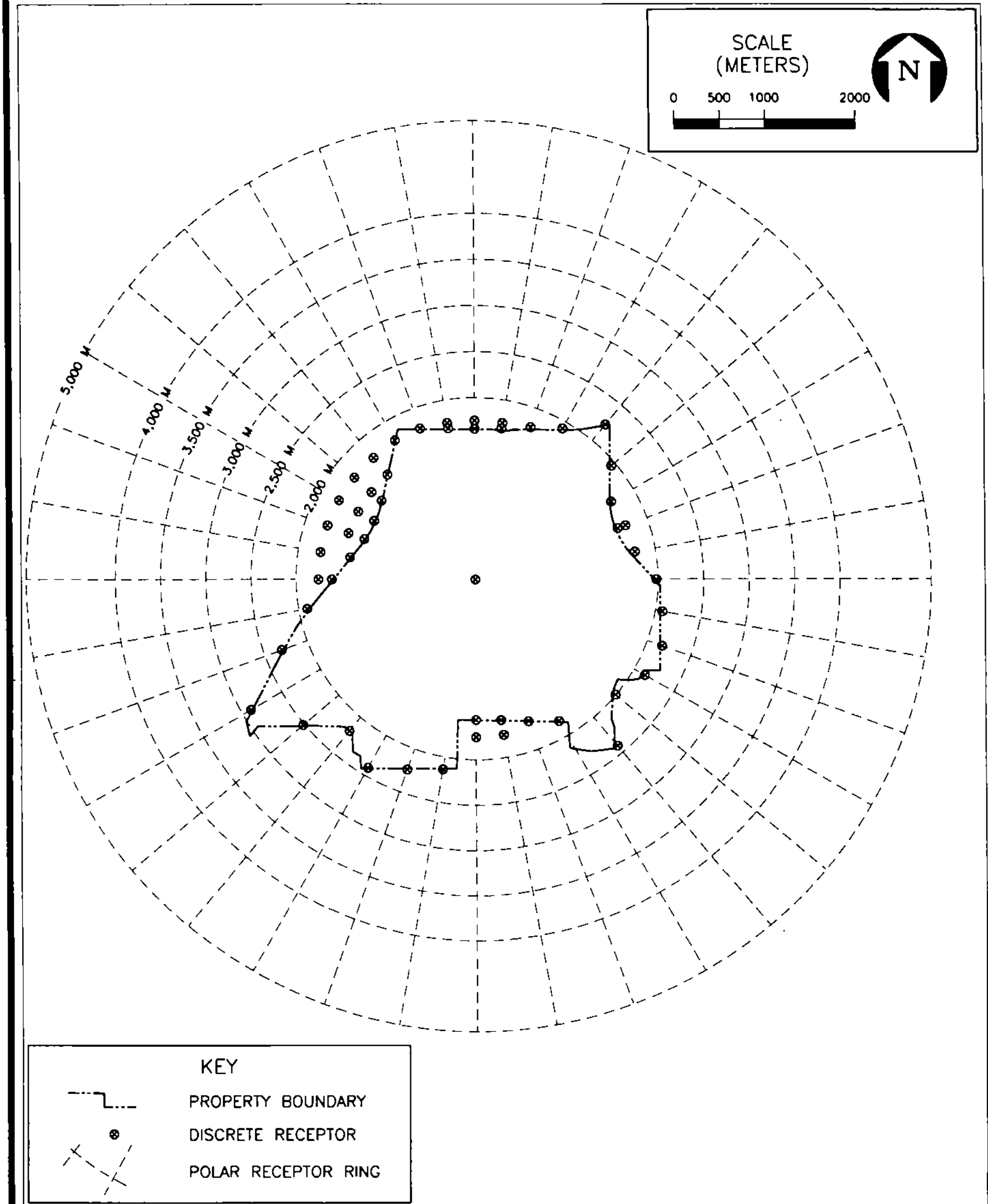

FIGURE 6-1.

LOCATIONS OF DISCRETE RECEPTORS AND CLOSE-IN RECEPTORS

Source: ECT, 1999.

TECO
TAMPA ELECTRIC

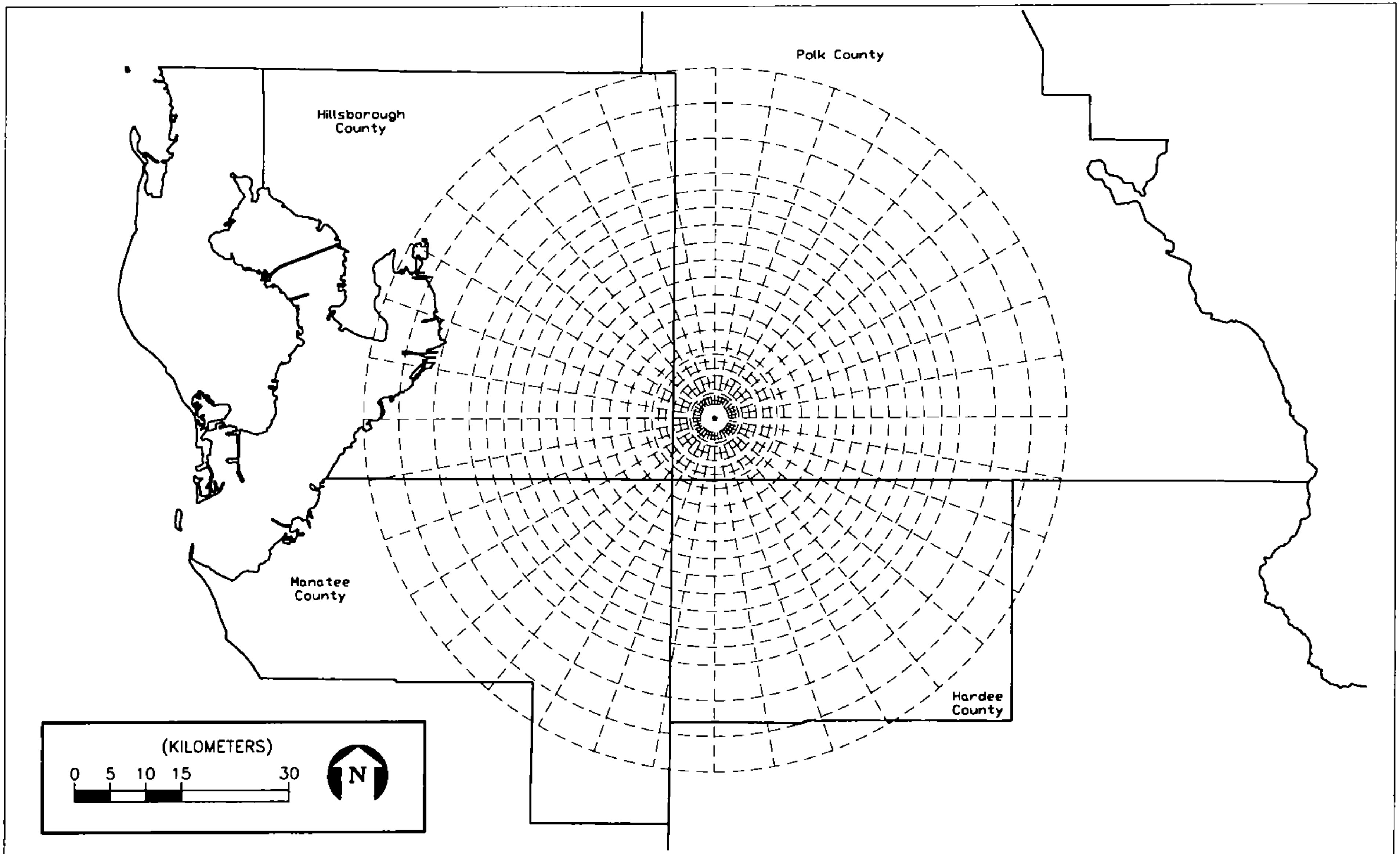

FIGURE 6-2.
POLAR RECEPTOR RINGS

Source: ECT, 1999.

TECO
TAMPA ELECTRIC

6.8 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC3 dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, the selected meteorological dataset consisted of St. Petersburg/Clearwater International Airport (SPG), Station ID 72211, surface data and Ruskin (RUS), Station ID 12842, upper air data. These data were obtained from the National Climatic Data Center (NCDC) for the 1992 through 1996 5-year period.

The surface and mixing height data for each of the 5 years were processed using EPA's PCRAMMET meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model.

6.9 MODELED EMISSION INVENTORY

Modeled on-property emission sources consisted of the two, new proposed CTG units. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the two new CTGs resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

Emission rates and stack parameters for the new CTG units were previously presented in Tables 2-1 through 2-8.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The SCREEN3 dispersion model was used to assess each of the 18 CTG operating cases (i.e., a matrix of three CTG loads [100, 75, and 50 percent], three ambient temperatures [20, 59, and 90°F], and two fuel types [natural gas and fuel oil] for each pollutant subject to PSD review [NO_2, SO_2, PM/PM_{10}, CO, and H_2SO_4]). The worst-case operating mode identified by the SCREEN3 model for each pollutant was then carried forward to the refined modeling for further analysis.

SCREEN3 model runs employed the specific stack exit temperature and exhaust gas velocity appropriate for each operating case. A nominal emission rate of 10.0 g/s was used for each case; model results were then scaled to reflect the maximum emission rates for each pollutant. Because the SCREEN3 model is a single-source model, the scaling procedure was based on maximum emissions from both CTGs. SCREEN3 model options used include rural dispersion, full meteorology, and automated receptors extending from 1,360 to 10,000 meters.

Tables 7-1 through 7-5 provide SCREEN3 model maximum 1-hour impacts for the CTG operating case for NO_2, SO_2, CO, PM_{10}, and H_2SO_4 mist, respectively. These Tables indicate, for each operating case, the maximum emission rate for both CTGs, SCREEN3 model results based on a nominal 10.0-g/s emission rate, emission rate scaling factor, scaled SCREEN3 model result, and location of maximum impact.

As shown in the SCREEN3 summary tables, the maximum 1-hour impact for NO_2, SO_2, CO, and H_2SO_4 mist are all occurred under Case 4 operating conditions (i.e., 100-percent load, fuel oil firing, and 59°F ambient temperature). For PM/PM_{10}, the maximum 1-hour SCREEN3 impact occurred under Case 1 conditions (i.e., 100-percent load, fuel oil firing, and 20°F ambient temperature). These worst-case operating cases were then further analyzed using the refined ISCST3 dispersion model.

Table 7-1. SCREEN3 Model Results—NO_2 Impacts; CT2 and CT3

Operating Scenarios					1-Hour Impacts ($\mu g/m^3$)			
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	CT Fuel	SCREEN3 Unadjusted Results*	Emission Rate Factor†	SCREEN3 Adjusted Results**	Downwind Distance (meters)
1	100	20	85.18	Fuel oil	2.12	8.52	18.06	1562
2	75	20	68.54	Fuel oil	2.53	6.85	17.34	1482
3	50	20	52.92	Fuel oil	2.96	5.29	15.66	1413
4	**100**	**59**	**80.38**	**Fuel oil**	**2.26**	**8.04**	**18.17**	**1532**
5	75	59	64.76	Fuel oil	2.67	6.48	17.29	1458
6	50	59	50.40	Fuel oil	3.10	5.04	15.62	1394
7	100	90	73.08	Fuel oil	2.43	7.31	17.76	1500
8	75	90	59.22	Fuel oil	2.82	5.92	16.70	1434
9	50	90	46.36	Fuel oil	3.27	4.64	15.16	1371
10	100	20	18.52	Natural gas	2.16	1.85	4.00	1553
11	75	20	14.70	Natural gas	2.61	1.47	3.84	1468
12	50	20	11.46	Natural gas	3.01	1.15	3.45	1406
13	100	59	17.34	Natural gas	2.32	1.73	4.02	1521
14	75	59	13.82	Natural gas	2.74	1.38	3.79	1446
15	50	59	10.88	Natural gas	3.16	1.09	3.44	1386
16	100	90	15.88	Natural gas	2.47	1.59	3.92	1492
17	75	90	12.94	Natural gas	2.90	1.29	3.75	1421
18	50	90	10.30	Natural gas	3.32	1.03	3.42	1365
					Maximum		**18.17**	

*Based on 10.0-g/s emission rate.
†Emission rate (in g/s) divided by 10.0 g/s.
**SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-2. SCREEN3 Model Results—SO_2 Impacts; CT2 and CT3

Operating Scenarios					1-Hour Impacts ($\mu g/m^3$)			
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	CT Fuel	SCREEN3 Unadjusted Results*	Emission Rate Factor†	SCREEN3 Adjusted Results**	Downwind Distance (meters)
1	100	20	26.24	Fuel oil	2.12	2.62	5.56	1562
2	75	20	21.28	Fuel oil	2.53	2.13	5.38	1482
3	50	20	16.60	Fuel oil	2.96	1.66	4.91	1413
4	**100**	**59**	**24.72**	**Fuel oil**	**2.26**	**2.47**	**5.59**	**1532**
5	75	59	20.10	Fuel oil	2.67	2.01	5.37	1458
6	50	59	15.80	Fuel oil	3.10	1.58	4.90	1394
7	100	90	22.48	Fuel oil	2.43	2.25	5.46	1500
8	75	90	18.40	Fuel oil	2.82	1.84	5.19	1434
9	50	90	14.56	Fuel oil	3.27	1.46	4.76	1371
10	100	20	2.48	Natural gas	2.16	0.25	0.54	1553
11	75	20	1.98	Natural gas	2.61	0.20	0.52	1468
12	50	20	1.58	Natural gas	3.01	0.16	0.48	1406
13	100	59	2.32	Natural gas	2.32	0.23	0.54	1521
14	75	59	1.88	Natural gas	2.74	0.19	0.52	1446
15	50	59	1.50	Natural gas	3.16	0.15	0.47	1386
16	100	90	2.14	Natural gas	2.47	0.21	0.53	1492
17	75	90	1.74	Natural gas	2.90	0.17	0.50	1421
18	50	90	1.42	Natural gas	3.32	0.14	0.47	1365
					Maximum		**5.59**	

*Based on 10.0-g/s emission rate.
†Emission rate (in g/s) divided by 10.0 g/s.
**SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-3. SCREEN3 Model Results—PM/PM_{10} Impacts; CT2 and CT3

Operating Scenarios					One-Hour Impacts (μg/m^3)			
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	CT Fuel	SCREEN3 Unadjusted Results*	Emission Rate Factor†	SCREEN3 Adjusted Results**	Downwind Distance (meters)
1	**100**	**20**	**6.80**	**Fuel oil**	**2.12**	**0.68**	**1.442**	1562
2	75	20	5.22	Fuel oil	2.53	0.52	1.32	1482
3	50	20	4.42	Fuel oil	2.96	0.44	1.31	1413
4	100	59	6.36	Fuel oil	2.26	0.64	1.437	1532
5	75	59	5.08	Fuel oil	2.67	0.51	1.36	1458
6	50	59	4.08	Fuel oil	3.10	0.41	1.26	1394
7	100	90	5.86	Fuel oil	2.43	0.59	1.42	1500
8	75	90	4.88	Fuel oil	2.82	0.49	1.38	1434
9	50	90	3.94	Fuel oil	3.27	0.39	1.29	1371
10	100	20	2.56	Natural gas	2.16	0.26	0.55	1553
11	75	20	2.50	Natural gas	2.61	0.25	0.65	1468
12	50	20	2.46	Natural gas	3.01	0.25	0.74	1406
13	100	59	2.54	Natural gas	2.32	0.25	0.59	1521
14	75	59	2.48	Natural gas	2.74	0.25	0.68	1446
15	50	59	2.44	Natural gas	3.16	0.24	0.77	1386
16	100	90	2.52	Natural gas	2.47	0.25	0.62	1492
17	75	90	2.46	Natural gas	2.90	0.25	0.71	1421
18	50	90	2.44	Natural gas	3.32	0.24	0.81	1365
					Maximum		**1.442**	

*Based on 10.0-g/s emission rate.
†Emission rate (in g/s) divided by 10.0 g/s.
**SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-4. SCREEN3 Model Results—CO Impacts; CT2 and CT3

Operating Scenarios					One-Hour Impacts ($\mu g/m^3$)			
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	CT Fuel	SCREEN3 Unadjusted Results*	Emission Rate Factor†	SCREEN3 Adjusted Results**	Downwind Distance (meters)
1	100	20	28.48	Fuel oil	2.12	2.85	6.038	1562
2	75	20	21.16	Fuel oil	2.53	2.12	5.35	1482
3	50	20	17.90	Fuel oil	2.96	1.79	5.30	1413
4	**100**	**59**	**26.72**	**Fuel oil**	**2.26**	**2.67**	**6.039**	**1532**
5	75	59	20.42	Fuel oil	2.67	2.04	5.45	1458
6	50	59	17.64	Fuel oil	3.10	1.76	5.47	1394
7	100	90	24.44	Fuel oil	2.43	2.44	5.94	1500
8	75	90	19.40	Fuel oil	2.82	1.94	5.47	1434
9	50	90	16.88	Fuel oil	3.27	1.69	5.52	1371
10	100	20	12.86	Natural gas	2.16	1.29	2.78	1553
11	75	20	10.34	Natural gas	2.61	1.03	2.70	1468
12	50	20	8.56	Natural gas	3.01	0.86	2.58	1406
13	100	59	12.10	Natural gas	2.32	1.21	2.81	1521
14	75	59	9.82	Natural gas	2.74	0.98	2.69	1446
15	50	59	8.06	Natural gas	3.16	0.81	2.55	1386
16	100	90	10.84	Natural gas	2.47	1.08	2.68	1492
17	75	90	9.08	Natural gas	2.90	0.91	2.63	1421
18	50	90	7.56	Natural gas	3.32	0.76	2.51	1365
					Maximum		**6.039**	

*Based on 10.0-g/s emission rate.
†Emission rate (in g/s) divided by 10.0 g/s.
**SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-5. SCREEN3 Model Results—H_2SO_4 Mist Impacts; CT2 and CT3

Operating Scenarios					One-Hour Impacts (µg/m³)			
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	CT Fuel	SCREEN3 Unadjusted Results*	Emission Rate Factor†	SCREEN3 Adjusted Results**	Downwind Distance (meters)
1	100	20	3.02	Fuel oil	2.12	0.30	0.640	1562
2	75	20	2.44	Fuel oil	2.53	0.24	0.62	1482
3	50	20	1.90	Fuel oil	2.96	0.19	0.56	1413
4	**100**	**59**	**2.84**	**Fuel oil**	**2.26**	**0.28**	**0.642**	**1532**
5	75	59	2.30	Fuel oil	2.67	0.23	0.61	1458
6	50	59	1.82	Fuel oil	3.10	0.18	0.56	1394
7	100	90	2.58	Fuel oil	2.43	0.26	0.63	1500
8	75	90	2.12	Fuel oil	2.82	0.21	0.60	1434
9	50	90	1.68	Fuel oil	3.27	0.17	0.55	1371
10	100	20	0.28	Natural gas	2.16	0.03	0.06	1553
11	75	20	0.22	Natural gas	2.61	0.02	0.06	1468
12	50	20	0.18	Natural gas	3.01	0.02	0.05	1406
13	100	59	0.26	Natural gas	2.32	0.03	0.06	1521
14	75	59	0.22	Natural gas	2.74	0.02	0.06	1446
15	50	59	0.18	Natural gas	3.16	0.02	0.06	1386
16	100	90	0.24	Natural gas	2.47	0.02	0.06	1492
17	75	90	0.20	Natural gas	2.90	0.02	0.06	1421
18	50	90	0.16	Natural gas	3.32	0.02	0.05	1365
					Maximum		**0.642**	

*Based on 10.0-g/s emission rate.
†Emission rate (in g/s) divided by 10.0 g/s.
**SCREEN3 unadjusted results multiplied by emission rate factor.

Source: ECT,

7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The refined ISCST3 model was used to model the operating cases identified by the SCREEN3 model to cause maximum impacts. ISCST3 model results for each year of meteorology evaluated (1985 to 1991) are summarized on Table 7-6 (annual NO_2 impacts), Table 7-7 (annual SO_2 impacts), Table 7-8 (3-hour SO_2 impacts), Table 7-9 (24-hour SO_2 impacts), Table 7-10 (annual PM/PM_{10} impacts), Table 7-11 (24-hour PM/PM_{10} impacts), Table 7-12 (1-hour CO impacts), and Table 7-13 (8-hour CO impacts).

Tables 7-6 through 7-13 demonstrate that Project impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2. Table 7-14 provides a summary of maximum Project impacts and PSD significant impact levels.

7.3 PSD CLASS I IMPACTS

Maximum impacts at the Chassahowitzka National Wildlife Refuge were conservatively estimated using the ISCST3 dispersion model. Table 7-15 provides a summary of maximum Project Class I area impacts and the EPA PSD Class I area significant impact levels.

The Chassahowitzka National Wildlife Refuge is located approximately 120 km northwest of the Polk Power Station. Accordingly, use of the ISCST3 dispersion model to predict impacts at this Class I area will yield conservative results (i.e., over-estimate actual impacts). In addition, short-term impacts were developed assuming fuel oil firing operating conditions. Maximum Class I impacts during natural gas firing will be significantly lower. As stated previously, the new simple cycle CTGs will operate with a fuel oil annual capacity factor of 10 percent (i.e., no more 876 hours per year at base load).

7.4 AIR TOXICS ASSESSMENT

The maximum 1-hour average SCREEN3 model impact was 0.642 micrograms per cubid meter ($\mu g/m^3$) for H_2SO_4 mist. Recommended EPA (EPA, 1992) multiplying factors for converting 1-hour averages to 8- and 24-hour averages are 0.7 and 0.4, respectively. Use of these factors yields maximum 8- and 24-hour average H_2SO_4 mist impacts of 0.449 and 0.257 $\mu g/m^3$, respectively. These impacts are well below the FDEP ambient reference concentrations (ARCs) for

Table 7-6. ISCST3 Model Results—Annual Average NO2 Impacts, Polk Power Station, CT2 and CT3

Maximum Annual Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.056	0.052	0.042	**0.073**	0.064
Emission Rate Scaling Factor†	0.836	0.836	0.836	**0.836**	0.836
Tier 1 Impact ($\mu g/m^3$)**	0.046	0.043	0.035	**0.061**	0.053
Tier 2 Impact ($\mu g/m^3$)‡	0.035	0.033	0.026	**0.045**	0.040
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	3.5	3.3	2.6	**4.5**	4.0
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	14.0	**14.0**	14.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	0.2	0.2	0.2	**0.3**	0.3
Receptor UTM Easting (m)	404,255.1	404,255.1	404,255.1	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,306.0	3,066,306.0	3,066,306.0	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	2,000	2,000	2,000	**2,000**	2,000
Direction From Grid Origin (Vector °)	120	120	120	**120**	120

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (assumed complete conversion of NO_x to NO_2 [i.e., NO_2/NO_x ratio of 1.0]).

‡Tier 1 impact times EPA national default NO2/NOx ratio of 0.75.

Source: *ECT, 1999.*

Table 7-7. ISCST3 Model Results—Annual Average SO2 Impacts, Polk Power Station, CT2 and CT3

Maximum Annual Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact (μg/m³)*	0.056	0.052	0.042	**0.073**	0.064
Emission Rate Scaling Factor†	0.182	0.182	0.182	**0.182**	0.182
Adjusted Impact (μg/m³)**	0.010	0.009	0.008	**0.013**	0.012
PSD Significant Impact (μg/m³)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	1.0	0.9	0.8	**1.3**	1.2
Receptor UTM Easting (m)	404,255.1	404,255.1	404,255.1	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,306.0	3,066,306.0	3,066,306.0	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	2,000	2,000	2,000	**2,000**	2,000
Direction From Grid Origin (Vector °)	120	120	120	**120**	120

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-8. ISCST3 Model Results—Annual Average PM/PM10 Impacts, Polk Power Station, CT2 and CT3

Maximum Annual Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact (μg/m³)*	0.056	0.052	0.042	**0.073**	0.064
Emission Rate Scaling Factor†	0.095	0.095	0.095	**0.095**	0.095
Adjusted Impact (μg/m³)**	0.005	0.005	0.004	**0.007**	0.006
PSD Significant Impact (μg/m³)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	0.5	0.5	0.4	**0.7**	0.6
Receptor UTM Easting (m)	404,255.1	404,255.1	404,255.1	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,306.0	3,066,306.0	3,066,306.0	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	2,000	2,000	2,000	**2,000**	2,000
Direction From Grid Origin (Vector °)	120	120	120	**120**	120

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-9. ISCST3 Model Results—Maximum 3-Hour Average SO2 Impacts; Polk Power Station, CT2 and CT3.

Maximum 3-Hour Impacts	1992	1993	1994	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	6.85	5.97	8.19	8.18	**11.33**
Emission Rate Scaling Factor†	1.236	1.236	1.236	1.236	**1.236**
Adjusted Impact ($\mu g/m^3$)**	8.47	7.38	10.12	10.12	**14.01**
PSD Significant Impact ($\mu g/m^3$)	25.0	25.0	25.0	25.0	**25.0**
Exceed PSD Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	33.9	29.5	40.5	40.5	**56.0**
Receptor UTM Easting (m)	404,051.3	404,255.1	404,255.1	404,051.3	**404,255.1**
Receptor UTM Northing (m)	3,066,023.8	3,066,306.0	3,066,306.0	3,066,023.8	**3,066,306.0**
Distance From Grid Origin (m)	1,995	2,000	2,000	1,995	**2,000**
Direction From Grid Origin (Vector °)	130	120	120	130	**120**
Date of Maximum Impact	4/3/92	3/13/93	2/25/94	6/28/95	**1/14/96**
Julian Date of Maximum Impact	94	72	56	180	**14**
Ending Hour of Maximum Impact	2400	1500	2400	0600	**2100**

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-10. ISCST3 Model Results—Maximum 24-Hour Average SO2 Impacts; Polk Power Station, CT2 and CT3.

Maximum 24-Hour Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	1.24	1.38	1.43	**1.80**	1.62
Emission Rate Scaling Factor†	1.236	1.236	1.236	**1.236**	1.236
Adjusted Impact ($\mu g/m^3$)**	1.53	1.71	1.76	**2.22**	2.00
PSD Significant Impact ($\mu g/m^3$)	5.0	5.0	5.0	**5.0**	5.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	30.7	34.1	35.2	44.5	**40.0**
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	13.0	13.0	13.0	**13.0**	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	11.8	13.1	13.5	**17.1**	15.4
Receptor UTM Easting (m)	404,255.1	404,255.1	405,987.1	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,306.0	3,066,306.0	3,065,306.0	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	2,000	2,000	4,000	**2,000**	2,000
Direction From Grid Origin (Vector °)	120	120	120	**120**	120
Date of Maximum Impact	5/31/92	3/13/93	12/25/94	**6/19/95**	1/14/96
Julian Date of Maximum Impact	152	72	359	**170**	14

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

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Table 7-11. ISCST3 Model Results - Maximum 24-Hour PM/PM_{10} Impacts; Polk Power Station, CT2 and CT3.

Maximum 24-Hour Impacts	1992	1993	1994	1995	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	1.12	1.33	1.34	**1.59**	1.32
Emission Rate Scaling Factor†	0.340	0.340	0.340	**0.340**	0.340
Adjusted Impact ($\mu g/m^3$)**	0.38	0.45	0.46	**0.54**	0.45
PSD Significant Impact ($\mu g/m^3$)	5.0	5.0	5.0	**5.0**	5.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	7.6	9.1	9.1	**10.8**	9.0
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	10.0	10.0	10.0	**10.0**	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	3.8	4.5	4.6	**5.4**	4.5
Receptor UTM Easting (m)	404,051.3	404,255.1	405,987.1	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,023.8	3,066,306.0	3,065,306.0	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	1,995	2,000	4,000	**2,000**	2,000
Direction From Grid Origin (Vector °)	130	120	120	**120**	120
Date of Maximum Impact	7/09/92	3/13/93	12/25/94	**6/19/95**	1/14/96
Julian Date of Maximum Impact	191	72	359	**170**	14

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

GDP-99\TPS\PPS\AIRPRM-H.XLS—020499

Table 7-12. ISCST3 Model Results—Maximum 1-Hour CO Impacts; Polk Power Station, CT2 and CT3.

Maximum 1-Hour Impacts	1992	1993	1994	1995	1996
Unadjusted ISCST3 Impact (µg/m^3)*	19.64	14.26	24.56	22.98	26.40
Emission Rate Scaling Factor†	1.336	1.336	1.336	1.336	1.336
Adjusted Impact (µg/m^3)**	26.23	19.06	32.82	30.71	35.27
PSD Significant Impact (µg/m^3)	2,000.0	2,000.0	2,000.0	2,000.0	2,000.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	1.3	1.0	1.6	1.5	1.8
Receptor UTM Easting (m)	404,688.1	404,255.1	404,255.1	404,255.1	404,255.1
Receptor UTM Northing (m)	3,066,056.0	3,066,306.0	3,066,306.0	3,066,306.0	3,066,306.0
Distance From Grid Origin (m)	2,500	2,000	2,000	2,000	2,000
Direction From Grid Origin (Vector °)	120	120	120	120	120
Date of Maximum Impact	5/31/92	12/21/93	2/25/94	6/28/95	1/14/96
Julian Date of Maximum Impact	152	355	56	179	14
Ending Hour of Maximum Impact	0300	2200	2200	0300	2100

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-13. ISCST3 Model Results—Maximum 8-Hour CO Impacts; Polk Power Station, CT2 and CT3.

Maximum 8-Hour Impacts	1992	1993	1994	**1995**	1996
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	3.62	2.62	4.05	**5.40**	4.86
Emission Rate Scaling Factor†	1.336	1.336	1.336	**1.336**	1.336
Adjusted Impact ($\mu g/m^3$)**	4.83	3.49	5.41	**7.22**	6.49
PSD Significant Impact ($\mu g/m^3$)	500.0	500.0	500.0	**500.0**	500.0
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	1.0	0.7	1.1	**1.4**	1.3
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	575.0	575.0	575.0	**575.0**	575.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	0.8	0.6	0.9	**1.3**	1.1
Receptor UTM Easting (m)	404,051.3	408,161.2	404,051.3	**404,255.1**	404,255.1
Receptor UTM Northing (m)	3,066,023.8	3,065,254.0	3,066,023.8	**3,066,306.0**	3,066,306.0
Distance From Grid Origin (m)	1,995	6,000	1,995	**2,000**	2,000
Direction From Grid Origin (Vector °)	130	110	130	**120**	120
Date of Maximum Impact	7/09/92	6/5/93	3/15/94	**6/19/95**	1/14/96
Julian Date of Maximum Impact	191	156	74	**170**	14
Ending Hour of Maximum Impact	2400	2400	0800	**2400**	2400

*Based on modeled emission rate of 10.0 g/s per CT/HRSG unit.

†Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 10.0-g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-14. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.045	1.0
CO	8-hour	5.40	500
	1-hour	35.27	2,000
PM	Annual	0.006	1.0
	24-hour	0.54	5.0
SO_2	Annual	0.013	1.0
	24-hour	2.22	5.0
	3-hour	14.01	25.0

Source: ECT, 1999.

Table 7-15. ISCST3 Model Results—Maximum Class I Area Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	EPA Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.005	0.1
PM	Annual	0.0006	0.2
	24-hour	0.05	0.3
SO_2	Annual	0.001	0.1
	24-hour	0.17	0.2
	3-hour	0.99	1.0

Source: ECT, 1999.

H_2SO_4 mist of 10.0 and 2.4 µg/m^3 for 8- and 24-hour average periods, respectively. Table 7-16 provides a summary of Project H_2SO_4 impacts and the FDEP ARC levels.

7.5 CONCLUSIONS

Comprehensive dispersion modeling using the SCREEN3 and refined ISCST3 models demonstrates that Project emission sources will result in ambient air quality impacts that are:

- Below PSD significant impact levels for all pollutants and all averaging periods.
- Below PSD *de minimis* ambient impact levels for all pollutants and all averaging periods.
- Below FDEP ARCs for H_2SO_4 mist.

Table 7-16. Summary of Worst-Case Estimates of Air Toxics Impacts Compared to FDEP ARCs

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	ARCs ($\mu g/m^3$)
H_2SO_4 mist	8-hour	0.449	10
	24-hour	0.257	2.4

Source: ECT, 1999.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring station is located in Nichols, Polk County, approximately 17 km north of the project site. The FDEP monitoring station at Nichols monitors PM_{10} and SO_2. The nearest FDEP station that monitors ozone is located in Lakeland, Polk County. The closest FDEP monitoring stations that monitor PM_{10} and SO_2 are situated in Nichols and Mulberry, Polk County, which are respectively located approximately 17 and 18 km north of the project site. The nearest FDEP stations that monitor NO_x and CO are located in Tampa, Hillsborough County, approximately 62 km northwest of the project site. The nearest FDEP station monitoring for lead is situated in Ruskin, Hillsborough County, approximately 50 km west of the project site. A summary of 1996 and 1997 ambient air quality data for these FDEP stations is provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several pollutants will be emitted from the Project in excess of their respective significant emission rates, preconstruction monitoring is required. However, the FDEP Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed facility. The results of these analyses are presented in detail in Section 7.2. The following paragraphs summarize the analyses results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 0.54 $\mu g/m^3$. This concentration is below the 10 $\mu g/m^3$ *de minimis* level ambient impact level.

Table 8-1. Summary of 1996 FDEP Ambient Air Quality Data

Pollutant	Site Location County	Site Location City	Site No.	Averaging Period	Sampling Period	Number of Observations	Ambient Concentration (ug/m^3) 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Polk	Auburndale	0120 001 F01	24-Hr	Jan-May	18	34	34	34		150*
				Annual						20	50†
		Lakeland	2160 007 F01	24-Hr	Jan-May	21	32	26	32		
				Annual						17	
		Mulberry	2860 006 F02	24-Hr	Jan-May	21	36	28	36		
				Annual						21	
		Nichols	3680 010 F02	24-Hr	Jan-Dec	61	75	45	75		
				Annual						22	
SO_2	Polk	Mulberry	2860 006 F02	1-Hr	Feb-Dec	7,272	204	165			
				3-Hr			150	124			1,300**
				24-Hr			57	43			260**
				Annual						11	60†
		Nichols	3680 010 F02	1-Hr	Jan-Dec	8,610	1258	354			
				3-Hr			432	257			1,300**
				24-Hr			86	80			260**
				Annual						15	60†
NO_2	Hillsborough	Tampa	4360 065 G01	1-Hr	Jan-Dec	8,637	130	100			
				Annual						18	100†
CO	Hillsborough	Tampa	4360 045 G01	1-Hr	Jan-Dec	8,669	9,200	6,900			40,000**
				8-Hr		-	4,600	4,600			10,000**
O_3	Polk	Lakeland	2160 005 F01	1-Hr	Jan-Dec	8,689	187	167			235‡
			2160 006 F01	1-Hr	Jan-Dec	8,718	194	181			235‡
Lead	Hillsborough	Ruskin	1800 003 G03	24-Hr							
					Jan-Mar	8				0.0	1.5†
					Apr-Jun	7				0.0	
					Jul-Sep	8				0.0	
					Oct-Dec	8				0.0	

*99th percentile
†Arithmetic mean
**2nd high
‡4th highest day with hourly value exceeding standard over a 3-year period

Source: FDEP, 1998.

Table 8-2. Summary of 1997 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Averaging Period	Sampling Period	Number of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Polk	Nichols	3680 010 F02	24-Hr	Jan-Dec	31	41	36	41		150*
				Annual						20	50†
SO_2	Polk	Mulberry	2860 006 F02	1-Hr	Jan-Dec	8,647	254	173			
				3-Hr			168	134			1,300**
				24-Hr			49	38			260**
				Annual						11	60†
		Nichols	3680 010 F02	1-Hr	Jan-Dec	8,680	246	199			
				3-Hr			176	148			1,300**
				24-Hr			53	48			260**
				Annual						17	60†
NO_2	Hillsborough	Tampa	4360 065 G01	1-Hr	Jan-Dec	8,087	111	111			
				Annual						18	100†
CO	Hillsborough	Tampa	4360 045 G01	1-Hr	Jan-Dec	8,527	5,750	5,750			40,000**
				8-Hr		-	3,450	3,450			10,000**
O_3	Polk	Lakeland	2160 005 F01	1-Hr	Jan-Dec	8,601	204	200			235‡
			2160 006 F01		Jan-Dec	8,686	216	196			
Lead	Hillsborough	Tampa	180 003 G03	24-Hr							
					Jan-Mar	7				0.0	1.5†
					Apr-Jun	8				0.0	
					Jul-Sep	7				0.0	
					Oct-Dec	8				0.0	

*99th percentile
†Arithmetic mean
**2nd high
‡4th highest day with hourly value exceeding standard over a 3-year period

Source: FDEP, 1998.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 7.2 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.05 $\mu g/m^3$. This concentration is below the 14-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate in accordance with the FDEP PSD regulations.

8.2.4 SO_2

The maximum 24-hour SO_2 impact was predicted to be 2.2 $\mu g/m^3$. This concentration is below the 13-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a reconstruction monitoring exemption is appropriate in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for projects subject to PSD review, evaluates project impacts pertaining to associated growth; soils, vegetation, and wildlife; and visibility impairment. Each of these topics is discussed in the following sections.

9.1 GROWTH IMPACT ANALYSIS

The purpose of the growth impact analysis is to quantify growth resulting from the construction and operation of the proposed project and assess air quality impacts that would result from that growth.

Impacts associated with construction of the Polk Power Station simple-cycle CTGs will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The new, simple-cycle CTGs are being constructed to meet general area electric power demands, and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the simple-cycle CTGs are projected to generate approximately ten new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the new simple-cycle CTGs will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the Polk Power Station due to operation of the proposed simple-cycle CTGs are well below applicable ambient air quality standards. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the Polk Power Station are anticipated. The following sections discuss potential impacts on the nearest Class I area; the Chassahowitzka National Wildlife Refuge (NWR).

9.2.1 IMPACTS ON SOILS

The U.S. Department of Agriculture (USDA) (1991a and 1991b) lists the primary soil type in Chassahowitzka as Weekiwachee-Durbin muck. This soil type is characterized by high levels of sulfur and organic content. Sulfur levels may approach 4 percent in the upper soil layer. Daily flooding by high tides cause the pH to vary between 6.1 and 7.8.

Typically, SO_2 represents the greatest threat to soil since this pollutant causes increased sulfur content and decreased pH. However, for this project, given the extremely low levels of SO_2 emitted, the distance from the source, the naturally high sulfur content of the Class I area soils, and the pH variability caused by tidal influences, no impacts to soils are expected.

9.2.2 IMPACTS ON VEGETATION

The Chassahowitzka NWR is a complex ecosystem of vegetation assemblages that depend on the subtle interplay of slight changes in elevation, salinity, hydroperiod, and edaphic factors for distribution, extent, and species composition. The mosaic of plant communities at the Chassahowitzka NWR is represented by pine woods and hammock forests within areas of higher ground, various freshwater forested and nonforested wetlands situated within lowland depressions that are inundated/saturated with fresh water for at least part of the year (mixed swamp, marsh, etc.) and brackish to saltwater wetlands such as salt marsh and mangrove swamp distributed at lower elevations on land normally inundated by tidal action and freshwater pulses from upland surface water runoff. The predominant flora associated with these associations is typically common to the central Florida region and characterized by a high diversity of terrestrial, wetland, and aquatic species. Common vascular taxa within the Chassahowitzka NWR would include slash pine, laurel oak, live oak, cabbage palm, sweet gum, red maple, saw palmetto, and gallberry in the inland areas and needlerush, red mangrove, cordgrass, and saltgrass in the brackish to marine reaches.

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of Polk Power Station due to operation of the simple-cycle CTGs would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka due to emissions from Polk Power Station simple-cycle CTGs will be far less, as presented previously. The potential for damage at the

Chassahowitzka NWR could, therefore, be considered negligible given the much lower air pollution impacts predicted at Chassahowitzka relative to the immediate Polk Power Station plant vicinity and the absence of any plant species at Chassahowitzka that would be especially sensitive to the very low predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

Wildlife resources in the 30,500-acre Chassahowitzka NWR are fairly typical of central Florida's Gulf Coast. The eastern portions of the site are fringed by hardwood swamp habitats, but the primary habitats are the estuarine and brackish marshes along with the saltwater bays containing many mangrove-covered islands. These habitats support large numbers of resident and migratory waterfowl, water birds, and shorebirds. Wading birds are also quite common. Deer, raccoons, black bears, otters, and bobcats are the notable mammals. Alligators are numerous. Bald eagles and the West Indian manatee are the primary endangered/threatened species utilizing the area.

Air pollution impacts to wildlife have been reported in the literature, although many of the incidents involved acute exposures to pollutants usually caused by unusual or highly concentrated releases or unique weather conditions. Generally, there are three ways pollutants may affect wildlife: through inhalation, through exposure with skin, and through ingestion (Newman, 1980). Ingestion is the most common means and can occur through eating or drinking of high concentrations of pollutants. Bioaccumulation is the process of animals collecting and accumulating pollutant levels in their bodies over time. Other animals that prey on these animals would then be ingesting concentrated pollutant levels.

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by this project will cause injury or death to wildlife. Concentrations of pollutants will be low, emissions will be dispersed over a large area, and mobility of wildlife will minimize their exposure to any unusual concentrations caused by equipment malfunction or unique weather patterns.

Bioaccumulation, particularly of mercury, has been a concern in Florida. There is increasing evidence that mercury may be naturally evolved in Florida and that, combined with manmade sources, is becoming bioaccumulated in certain fish and wildlife. It is unknown what naturally occurring levels may be present in onsite fish and wildlife. However, the likelihood that the small amount attributable to this project would all be methylated, end up in the food chain, and then consumed by predators is considered negligible.

The acid rain effects on wildlife in Florida are primarily those related to aquatic animals. Acidified water may prevent fish egg hatching, damage larvae, and lower immunity factors in adult fish (Barker, 1983). Acid rain can also result in release of metals (especially aluminum) from lake sediments; this can cause a biochemical deterioration of fish gills leading to death by suffocation. However, the sensitivity of Florida lakes to acid rain is in question. Florida lakes have a wide natural range of pH (from 4 pH units to 8.8 pH units). Most well-buffered lakes are in central and south Florida, and rainfall is in the pH range of 4.8 to 5.1. According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. The air emissions from Polk Power Station simple-cycle CTGs that could contribute to the formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife at Chassahowitzka.

In conclusion, it is unlikely the projected air emission levels from the Polk Power Station simple-cycle CTGs will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWR.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the simple-cycle CTGs. Opacity of the simple-cycle CTG exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the CTGs will be low due to the primary use of pipeline quality natural gas and low sulfur, low ash distillate fuel oil as the back-up fuel source. The simple-cycle CTGs will comply with all applicable FDEP requirements pertaining to visible emissions.

A Level 1 visibility screening analysis was conducted using the VISCREEN program, consistent with EPA (1988) guidance. Emissions input to the VISCREEN program were the maximum short-term (g/s) emission rates for primary PM, NO_x, and H_2SO_4 mist from the proposed simple-cycle CTGs. These rates were 6.8 g/s of PM, 85.18 g/s of NO_x, and 3.02 g/s of H_2SO_4 mist. Table 9-1 summarizes the results of the Level 1 analysis, which, even with the conservative assumptions inherent to such an analysis, resulted in impact values well below the screening thresholds. Therefore, it could be concluded that Polk Power Station simple-cycle CTG emissions will not cause impairment of visibility in the Chassahowitzka Class I area.

Table 9-1. Visual Effects Screening Analysis

```
                 Visual Effects Screening Analysis for
                   Source: Polk Power Station SC CT
                   Class I Area: CHASSAHOWITZKA NWA


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

   Particulates      6.80  G  /S
   NOx (as NO2)     85.18  G  /S
   Primary NO2        .00  G  /S
   Soot               .00  G  /S
   Primary SO4       3.02  G  /S


    **** Default Particle Characteristics Assumed

               Transport Scenario Specifications:

    Background Ozone:                    .04 ppm
    Background Visual Range:           65.00 km
    Source-Observer Distance:         115.00 km
    Min. Source-Class I Distance:     115.00 km
    Max. Source-Class I Distance:     122.00 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 NOT Exceeded
                                     Delta E       Contrast
                                   ===========   ============
Backgrnd Theta Azi Distance Alpha Crit  Plume    Crit  Plume
======== ===== === ======== ===== ====  =====    ====  =====
 SKY      10.  84.  115.0    84.  2.00   .719     .05  -.000
 SKY     140.  84.  115.0    84.  2.00   .334     .05  -.009
 TERRAIN  10.  84.  115.0    84.  2.00   .237     .05   .003
 TERRAIN 140.  84.  115.0    84.  2.00   .062     .05   .003


         Maximum Visual Impacts OUTSIDE Class I Area
          Screening Criteria ARE NOT Exceeded
                                     Delta E       Contrast
                                   ===========   ============
Backgrnd Theta Azi Distance Alpha Crit  Plume    Crit  Plume
======== ===== === ======== ===== ====  =====    ====  =====
 SKY      10.  65.  107.3   104.  2.00   .757     .05  -.000
 SKY     140.  65.  107.3   104.  2.00   .349     .05  -.010
 TERRAIN  10.  45.   97.8   124.  2.00   .311     .05   .004
 TERRAIN 140.  45.   97.8   124.  2.00   .086     .05   .004
```

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ATTACHMENT A—

APPLICATION FOR AIR PERMIT - LONG FORM

ECT
Environmental Consulting & Technology, Inc.

Scope of Application

This Application for Air Permit addresses the following emissions unit(s) at the facility. An Emissions Unit Information Section (a Section III of the form) must be included for each emissions unit listed.

Emissions Unit ID	Description of Emissions Unit	Permit Type
006	Combustion Turbine Generator Unit No. 2	AC1A
007	Combustion Turbine Generator Unit No. 3	AC1A

Purpose of Application and Category

Check one (except as otherwise indicated):

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

This Application for Air Permit is submitted to obtain:

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

[ ] Initial air operation permit under Chapter 62-213, F.A.C., for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ______________________________

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

Operation permit to be renewed: ______________________________

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

Current construction permit number: ______________________________

Operation permit to be revised: ______________________________

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

Operation permit to be revised/corrected: 1050233001AV

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

Operation permit to be revised: ______________________________

Reason for revision: ______________________________

____

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

This Application for Air Permit is submitted to obtain:

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

Current operation/construction permit number(s): ____________________

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

Operation permit to be renewed: ____________________

[ ] Air operation permit revision for a synthetic non-Title V source. Give reason for revision; e.g., to address one or more newly constructed or modified emissions units.

Operation permit to be revised: ____________________

Reason for revision: ____________________

____

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

This Application for Air Permit is submitted to obtain:

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

Current operation permit number(s), if any: 1050233001AV

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

Current operation permit number(s): ____________________

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

Application Processing Fee

Check one:

[X] Attached - Amount: $ 7,500 [ ] Not Applicable.

Construction/Modification Information

1.	Description of Proposed Project or Alterations: Project consists of the addition of two nominal 165-MW General Electric 7241 FA simple cycle combustion turbine generators (CTGs). CTGs are fired primarily using pipeline quality natural gas with low-sulfur, distillate fuel oil serving as a backup fuel. The new simple-cycle CTGs will operate at annual capacity factors up to 50 and 10 percent for natural gas and oil firing, respectively.
2.	Projected or Actual Date of Commencement of Construction: October 1999.
3.	Projected Date of Completion of Construction: 2nd quarter of 2000 (CTG No. 2), 3rd quarter of 2002 (CTG No. 2)

Professional Engineer Certification

1.	Professional Engineer Name: Thomas W. Davis Registration Number: 36777
2.	Professional Engineer Mailing Address: Organization/Firm: Environmental Consulting & Technology, Inc. Street Address: 3701 Northwest 98th Street City: Gainesville State: Florida Zip Code: 32606
3.	Professional Engineer Telephone Numbers: Telephone: (352) 332-0444 Fax: (352) 332-6722

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis 2/4/99

Signature Date

(seal)

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact: Mr. James Hunter Administrator – Air Programs, Environmental Planning	
2. Application Contact Mailing Address: Organization/Firm: Tampa Electric Company Street Address: 6499 U. S. Highway 41 North City: Apollo Beach State: FL Zip Code: 33572-9200	
3. Application Contact Telephone Numbers: Telephone: (813) 641-5033	Fax: (813) 641-5081

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17	East (km): 402.45		North (km): 3067.35
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
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 (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: David Knapp, Environmental Coordinator			
2. Facility Contact Mailing Address: Organization/Firm: Tampa Electric Company Street Address: P.O. Box 775 City: Mulberry		State: FL	Zip Code: 33860-0775
3. Facility Contact Telephone Numbers: Telephone: (813) 228-1111		Fax: (813) 428-5927	

Facility Regulatory Classifications

1. Small Business Stationary Source? [ ] Yes	[X] No	[ ] Unknown
2. Title V Source? [X] Yes	[ ] No	
3. Synthetic Non-Title V Source? [ ] Yes	[X] No	
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)? [X] Yes	[ ] No	
5. Synthetic Minor Source of Pollutants Other than HAPs? [ ] Yes	[X] No	
6. Major Source of Hazardous Air Pollutants (HAPs)? [ ] Yes	[X] No	
7. Synthetic Minor Source of HAPs? [ ] Yes	[X] No	
8. One or More Emissions Units Subject to NSPS? [X] Yes	[ ] No	
9. One or More Emission Units Subject to NESHAP? [ ] Yes	[X] No	
10. Title V Source by EPA Designation? [ ] Yes	[X] No	
11. Facility Regulatory Classifications Comment (limit to 200 characters):		

B. FACILITY REGULATIONS

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not applicable.

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment A-1	

C. FACILITY POLLUTANTS

Facility Pollutant Information

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

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant 1 of 6

1. Pollutant Emitted: NOx		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds major source threshold of 100 tpy. No emissions cap is requested.		

Facility Pollutant Detail Information: Pollutant 2 of 6

1. Pollutant Emitted: CO		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds major source threshold of 100 tpy. No emissions cap is requested.		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant 3 of 6

1. Pollutant Emitted: PM		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds major source threshold of 100 tpy. No emissions cap is requested.		

Facility Pollutant Detail Information: Pollutant 4 of 6

1. Pollutant Emitted: PM10		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds major source threshold of 100 tpy. No emissions cap is requested.		

D. FACILITY POLLUTANT DETAIL INFORMATION

Facility Pollutant Detail Information: Pollutant 5 of 6

1. Pollutant Emitted: SO2		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds major source threshold of 100 tpy. No emissions cap is requested.		

Facility Pollutant Detail Information: Pollutant 6 of 6

1. Pollutant Emitted: SAM		
2. Requested Emissions Cap:	(lb/hour)	(tons/year)
3. Basis for Emissions Cap Code:		
4. Facility Pollutant Comment (limit to 400 characters): Pollutant exceeds PSD significant emission rate threshold of 7 tpy. No emissions cap is requested.		

E. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location: [X] Attached, Figure 2-3 [ ] Not Applicable [ ] Waiver Requested	
2. Facility Plot Plan: [X] Attached, Figure 2-4 [ ] Not Applicable [ ] Waiver Requested	
3. Process Flow Diagram(s): [X] Attached, Figure 2-5 [ ] Not Applicable [ ] Waiver Requested	
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: Att. A-2 [ ] Not Applicable [ ] Waiver Requested	
5. Fugitive Emissions Identification: [ ] [X] Not Applicable [ ] Waiver Requested	
6. Supplemental Information for Construction Permit Application: [X] PSD Application [ ] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

(Previously submitted, see Title V Permit Application)

7. List of Proposed Exempt Activities: [ ] Attached, Document ID:______ [ ] Not Applicable (	
8. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable	
9. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable	
10. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable	

11. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
12. Compliance Assurance Monitoring Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan Submitted to Implementing Agency – Verification Attached, Document ID:________ [ ] Plan to be Submitted to Implementing Agency by Required Date [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID: ________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID: ________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

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

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

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

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

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

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

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

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

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Combustion Turbine Generator Unit No. 2		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown 006		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): Emissions unit consists of one General Electric (GE) 7241 FA simple cycle combustion turbine generator (CTG) with a nominal rating of 165 megawatts (MW). The CTG will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a backup fuel.		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): Dry low-NO_x combustors (natural gas-firing)
2. Control Device or Method Code: 25

Emissions Unit Control Equipment

B.

1. Description (limit to 200 characters): Water injection (distillate fuel oil-firing)	
2. Control Device or Method Code: 28	

C.

1. Description (limit to 200 characters):	
2. Control Device or Method Code:	

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

Emissions Unit Details

1. Initial Startup Date: 2nd Quarter 2000	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer: General Electric	Model Number: PG7241(FA)
4. Generator Nameplate Rating: 170	MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	2,066 (HHV)	mmBtu/hr
2. Maximum Incineration Rate: lb/hr		tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): Maximum heat input is at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load . fuel type, and ambient temperature.		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:		
	24 hours/day	7 days/week
	52 weeks/year	5,256 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not applicable

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: CTG No. 2	
2. Emission Point Type Code: [X] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W	
6. Stack Height:	75 feet
7. Exit Diameter:	29 feet
8. Exit Temperature:	1,117°F

9. Actual Volumetric Flow Rate:	2,384,051 acfm
10. Percent Water Vapor :	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): Stack temperature and flow rate are at 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment: 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Combustion turbine fired with pipeline quality natural gas.	
2. Source Classification Code (SCC): 20100201	
3. SCC Units: Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate: 1.848	5. Maximum Annual Rate: 8,094.2
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 1,025	
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) is higher heating value (HHV).	

Segment Description and Rate: Segment: 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Combustion turbine fired with distillate fuel oil.	
2. Source Classification Code (SCC): 20100101	
3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate: 14.243	5. Maximum Annual Rate: 12,476.9
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.05	8. Maximum Percent Ash: 0.01
9. Million Btu per SCC Unit: 139	
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) is higher heating value (HHV).	

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

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOx	025		EL
2 - CO			EL
3 - PM			EL
4 - PM10			EL
5 - SO2			EL
6 - SAM			EL
7 - VOC			EL

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

Pollutant Detail Information:

1. Pollutant Emitted: NOx		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	338.0 lb/hour	290.5 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		_______ to _______ tons/year
6. Emission Factor: Reference: GE data	338.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 68.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 319.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	10.5 ppmvd @ 15% O_2
4. Equivalent Allowable Emissions: 73.5 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 20 (initial), NO_x CEMS	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	42 ppmvd @ 15% O_2
4. Equivalent Allowable Emissions: 338.0 lb/hr	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 20 (initial), NO_x CEMS	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: CO		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	113.0 lb/hour	151.6 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: GE data	113.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 48.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 106.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	15 ppmvd
4. Equivalent Allowable Emissions: 51.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	33 ppmvd
4. Equivalent Allowable Emissions: 113.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: PM	
2. Total Percent Efficiency of Control:	%
3. Potential Emissions: 27.0 lb/hour	33.1 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year
6. Emission Factor: 27.0 Units lb/hr Reference: GE data	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5	
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 10.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 25.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.	
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):	

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	10% opacity
4. Equivalent Allowable Emissions: 27.0 lb/hour	33.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): Opacity limit applicable for both natural gas and distillate fuel oil-firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hr	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

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

Pollutant Detail Information:

1. Pollutant Emitted: PM10	
2. Total Percent Efficiency of Control:	%
3. Potential Emissions: 27.0 lb/hour	33.1 tons/year
4. Synthetically Limited? [X] Yes [ ] No	
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	_______ to _______ tons/year
6. Emission Factor: 27.0 Units lb/hr Reference: GE data	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5	
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 10.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 25.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.	
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):	

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units: 10% opacity	
4. Equivalent Allowable Emissions: 27.0 lb/hour	33.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): Opacity limit applicable for both natural gas and distillate fuel oil-firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hr	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

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

Pollutant Detail Information:

1. Pollutant Emitted: SO2		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	104.1 lb/hour	63.2 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: Reference: Mass balance	104.1 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [2] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): (0.05 lb S/100 lb oil) x (104,1210 lb oil/hr x (2 lb SO_2/1 lb S) = 104.1 lb/hr SO_2 Annual emissions based on 9.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 98.1 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	2.0 gr S/100 scf
4. Equivalent Allowable Emissions: 9.8 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	0.05 weight % S
4. Equivalent Allowable Emissions: 104.1 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: SAM

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 12.0 lb/hour 7.3 tons/year

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

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

6. Emission Factor: 12.0 Units lb/hr
Reference: Mass balance

7. Emissions Method Code:
[ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5

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

$(104.1 \text{ lb/hr } SO_2) \times (7.5/100) \times (98 \text{ lb } H_2SO_4/64 \text{ lb } SO_2) = 12.0 \text{ lb/hr } H_2SO_4$

Annual emissions based on 1.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 11.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.

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

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	2.0 gr S/100 scf
4. Equivalent Allowable Emissions: 1.1 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	0.05 weight % S
4. Equivalent Allowable Emissions: 12.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: VOC		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	15.0 lb/hour	36.8 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: GE data	15.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 14.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 14.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page) N/A

A.

1. Basis for Allowable Emissions Code: Other
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7 ppmvd
4. Equivalent Allowable Emissions: 15.0 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.

B.

1. Basis for Allowable Emissions Code: Other
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7 ppmvd
4. Equivalent Allowable Emissions: 15.0 lb/hour N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: 10			
2. Basis for Allowable Opacity:	[ ] Rule	[X] Other	
3. Requested Allowable Opacity: Normal Conditions: 10 % Maximum Period of Excess Opacity Allowed:	Exceptional Conditions:	%	min/hour
4. Method of Compliance: EPA Reference Method 9.			
5. Visible Emissions Comment (limit to 200 characters): Rule 62-212.400(5)(c), F.A.C. (BACT)			

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:			
2. Basis for Allowable Opacity:	[X] Rule	[ ] Other	
3. Requested Allowable Opacity: Normal Conditions: % Maximum Period of Excess Opacity Allowed:	Exceptional Conditions:	100 %	60 min/hour
4. Method of Compliance: EPA Reference Method 9			
5. Visible Emissions Comment (limit to 200 characters): Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C.			

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement: [X] Rule [ ] Other	
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

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

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

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

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

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

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[X] C	[ ] E	[ ] Unknown
4. Baseline Emissions:			
PM		lb/hour	tons/year
SO2		lb/hour	tons/year
NO2			tons/year
5. PSD Comment (limit to 200 characters):			

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Figure 2-5	[ ] Not Applicable	[ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Att. A-3	[ ] Not Applicable	[ ] Waiver Requested
3. Detailed Description of Control Equipment [X], Section 5.0	[ ] Not Applicable	[ ] Waiver Requested
4. Description of Stack Sampling Facilities To be provided. [ ] Attached, Document ID:_______	[ ] Not Applicable	[ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:_______ [ ] Previously submitted, Date:_______________ [X] Not Applicable		
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:_______	[X] Not Applicable	
7. Operation and Maintenance Plan [ ] Attached, Document ID:_______	[X] Not Applicable	
8. Supplemental Information for Construction Permit Application See PSD Application. [ ] Attached, Document ID:_____	[ ] Not Applicable	
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:_______	[X] Not Applicable	

Additional Supplemental Requirements for Category I Applications Only

(Previously submitted, see Title V Permit Application)

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

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through L as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application. Some of the subsections comprising the Emissions Unit Information Section of the form are intended for regulated emissions units only. Others are intended for both regulated and unregulated emissions units. Each subsection is appropriately marked.

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

Type of Emissions Unit Addressed in This Section

1. Regulated or Unregulated Emissions Unit? Check one:

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

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

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

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

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

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

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

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section (limit to 60 characters): Combustion Turbine Generator Unit No. 3		
2. Emissions Unit Identification Number: [ ] No Corresponding ID [ ] Unknown 007		
3. Emissions Unit Status Code: C	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code: 49
6. Emissions Unit Comment (limit to 500 characters): Emissions unit consists of one General Electric (GE) 7241 FA simple cycle combustion turbine generator (CTG) with a nominal rating of 165 megawatts (MW). The CTG will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a backup fuel.		

Emissions Unit Control Equipment

A.

1. Description (limit to 200 characters): Dry low-NO_x combustors (natural gas-firing)
2. Control Device or Method Code: 25

Emissions Unit Control Equipment

B.

1. Description (limit to 200 characters): Water injection (distillate fuel oil-firing)
2. Control Device or Method Code: 28

C.

1. Description (limit to 200 characters):
2. Control Device or Method Code:

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

Emissions Unit Details

1. Initial Startup Date: 2nd Quarter 2001	
2. Long-term Reserve Shutdown Date:	
3. Package Unit: Manufacturer: General Electric	Model Number: PG7241(FA)
4. Generator Nameplate Rating: 170	MW
5. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate:	2,066 (HHV)	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate:		
4. Maximum Production Rate:		
5. Operating Capacity Comment (limit to 200 characters): Maximum heat input is at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load , fuel type, and ambient temperature.		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule:	
24 hours/day	7 days/week
52 weeks/year	5,256 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Rule Applicability Analysis (Required for Category II applications and Category III applications involving non Title-V sources. See Instructions.)

Not applicable

List of Applicable Regulations (Required for Category I applications and Category III applications involving Title-V sources. See Instructions.)

See Attachment A-1	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: CTG No. 3	
2. Emission Point Type Code: [X] 1 [ ] 2 [ ] 3 [ ] 4	
3. Descriptions of Emissions Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A	
5. Discharge Type Code: [ ] D [ ] F [ ] H [ ] P [ ] R [X] V [ ] W	
6. Stack Height:	75 feet
7. Exit Diameter:	29 feet
8. Exit Temperature:	1,117°F

9. Actual Volumetric Flow Rate:	2,384,051 acfm
10. Percent Water Vapor :	%
11. Maximum Dry Standard Flow Rate:	dscfm
12. Nonstack Emission Point Height:	feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): Stack temperature and flow rate are at 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with load, fuel type, and ambient temperature.	

F. SEGMENT (PROCESS/FUEL) INFORMATION
(Regulated and Unregulated Emissions Units)

Segment Description and Rate: Segment: 1 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Combustion turbine fired with pipeline quality natural gas.	
2. Source Classification Code (SCC): 20100201	
3. SCC Units: Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate: 1.848	5. Maximum Annual Rate: 8,094.2
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur:	8. Maximum Percent Ash:
9. Million Btu per SCC Unit: 1,025	
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) is higher heating value (HHV).	

Segment Description and Rate: Segment: 2 of 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) (limit to 500 characters): Combustion turbine fired with distillate fuel oil.	
2. Source Classification Code (SCC): 20100101	
3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate: 14.243	5. Maximum Annual Rate: 12,476.9
6. Estimated Annual Activity Factor:	
7. Maximum Percent Sulfur: 0.05	8. Maximum Percent Ash: 0.01
9. Million Btu per SCC Unit: 139	
10. Segment Comment (limit to 200 characters): Fuel heat content (Field 9) is higher heating value (HHV).	

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

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOx	025		EL
2 – CO			EL
3 – PM			EL
4 - PM10			EL
5 - SO2			EL
6 – SAM			EL
7 – VOC			EL

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

Pollutant Detail Information:

1. Pollutant Emitted: NOx		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	338.0 lb/hour	290.5 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: GE data	338.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 68.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 319.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	10.5 ppmvd @ 15% O_2
4. Equivalent Allowable Emissions: 73.5 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 20 (initial), NO_x CEMS	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	42 ppmvd @ 15% O_2
4. Equivalent Allowable Emissions: 338.0 lb/hr	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 20 (initial), NO_x CEMS	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: CO		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	113.0 lb/hour	151.6 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: GE data	113.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 48.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 106.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	15 ppmvd
4. Equivalent Allowable Emissions: 51.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	33 ppmvd
4. Equivalent Allowable Emissions: 113.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 10	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: PM

2. Total Percent Efficiency of Control: %

3. Potential Emissions: 27.0 lb/hour 33.1 tons/year

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

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

6. Emission Factor: 27.0 Units lb/hr
   Reference: GE data

7. Emissions Method Code:
   [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5

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

   Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 10.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 25.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.

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

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Rule	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	10% opacity
4. Equivalent Allowable Emissions: 27.0 lb/hour	33.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): Opacity limit applicable for both natural gas and distillate fuel oil-firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hr	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

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

Pollutant Detail Information:

1. Pollutant Emitted: PM10		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	27.0 lb/hour	33.1 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: Reference: GE data	27.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 10.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 25.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	10% opacity
4. Equivalent Allowable Emissions: 27.0 lb/hour	33.1 tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 9.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): Opacity limit applicable for both natural gas and distillate fuel oil-firing.	

B.

1. Basis for Allowable Emissions Code:	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	
4. Equivalent Allowable Emissions: lb/hr	tons/year
5. Method of Compliance (limit to 60 characters):	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) (limit to 200 characters):	

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

Pollutant Detail Information:

1. Pollutant Emitted: SO2		
2. Total Percent Efficiency of Control:	%	
3. Potential Emissions:	104.1 lb/hour	63.2 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: Reference: Mass balance	104.1 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [2] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): (0.05 lb S/100 lb oil) x (104,1210 lb oil/hr x (2 lb SO_2/1 lb S) = 104.1 lb/hr SO_2 Annual emissions based on 9.2 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 98.1 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	2.0 gr S/100 scf
4. Equivalent Allowable Emissions: 9.8 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	0.05 weight % S
4. Equivalent Allowable Emissions: 104.1 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: SAM		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	12.0 lb/hour	7.3 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: Mass balance	12.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [X] 2 [ ] 3 [ ] 4 [ ] 5		
8. Calculation of Emissions (limit to 600 characters): (104.1 lb/hr SO_2) x (7.5/100) x (98 lb H_2SO_4/64 lb SO_2) = 12.0 lb/hr H_2SO_4 Annual emissions based on 1.1 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 11.3 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page)

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	2.0 gr S/100 scf
4. Equivalent Allowable Emissions: 1.1 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	0.05 weight % S
4. Equivalent Allowable Emissions: 12.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): Fuel analysis for sulfur content.	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

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

Pollutant Detail Information:

1. Pollutant Emitted: VOC		
2. Total Percent Efficiency of Control:		%
3. Potential Emissions:	15.0 lb/hour	36.8 tons/year
4. Synthetically Limited? [X] Yes [ ] No		
5. Range of Estimated Fugitive/Other Emissions: [ ] 1 [ ] 2 [ ] 3		______ to ______ tons/year
6. Emission Factor: Reference: GE data	15.0 Units lb/hr	
7. Emissions Method Code: [ ] 0 [ ] 1 [ ] 2 [ ] 3 [ ] 4 [X] 5		
8. Calculation of Emissions (limit to 600 characters): Hourly emission rate based on GE data for 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 14.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 14.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 876 hrs/yr.		
9. Pollutant Potential/Estimated Emissions Comment (limit to 200 characters):		

Allowable Emissions (Pollutant identified on front of page) N/A

A.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	7 ppmvd
4. Equivalent Allowable Emissions: 15.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for natural gas-firing.	

B.

1. Basis for Allowable Emissions Code: Other	
2. Future Effective Date of Allowable Emissions:	
3. Requested Allowable Emissions and Units:	7 ppmvd
4. Equivalent Allowable Emissions: 15.0 lb/hour	N/A tons/year
5. Method of Compliance (limit to 60 characters): EPA Reference Method 18 or 25	
6. Pollutant Allowable Emissions Comment (Desc. Of Related Operating Method/Mode) (limit to 200 characters): FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable for distillate fuel oil-firing.	

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: 10	
2. Basis for Allowable Opacity: [ ] Rule [X] Other	
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: EPA Reference Method 9.	
5. Visible Emissions Comment (limit to 200 characters): Rule 62-212.400(5)(c), F.A.C. (BACT)	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:	
2. Basis for Allowable Opacity: [X] Rule [ ] Other	
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: EPA Reference Method 9	
5. Visible Emissions Comment (limit to 200 characters): Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: EM	2. Pollutant(s): NO_x
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	
6. Performance Specification Test Date:	
7. Continuous Monitor Comment (limit to 200 characters): Required by 40 CFR Part 75 (Acid Rain Program). Specific CEMS information will be provided to FDEP when available.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION
(Regulated and Unregulated Emissions Units)

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

If the emissions unit addressed in this section emits particulate matter or sulfur dioxide, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for particulate matter or sulfur dioxide. Check the first statement, if any, that applies and skip remaining statements.

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

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

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

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

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

2. Increment Consuming for Nitrogen Dioxide?

If the emissions unit addressed in this section emits nitrogen oxides, answer the following series of questions to make a preliminary determination as to whether or not the emissions unit consumes PSD increment for nitrogen dioxide. Check first statement, if any, that applies and skip remaining statements.

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

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

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

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

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

3. Increment Consuming/Expanding Code:			
PM	[X] C	[ ] E	[ ] Unknown
SO2	[X] C	[ ] E	[ ] Unknown
NO2	[X] C	[ ] E	[ ] Unknown
4. Baseline Emissions:			
PM		lb/hour	tons/year
SO2		lb/hour	tons/year
NO2			tons/year
5. PSD Comment (limit to 200 characters):			

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

Supplemental Requirements for All Applications

1. Process Flow Diagram [X] Attached, Figure 2-5	[ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Att. A-3	[ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X], Section 5.0	[ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________	To be provided. [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:______________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________	[X] Not Applicable
7. Operation and Maintenance Plan [ ] Attached, Document ID:________	[X] Not Applicable
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:______	See PSD Application. [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________	[X] Not Applicable

Additional Supplemental Requirements for Category I Applications Only

(Previously submitted, see Title V Permit Application)

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

ATTACHMENT A-1

REGULATORY APPLICABILITY ANALYSES

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CTG-2, CTG-3	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 **(future requirement)**.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CTG-2, CTG-3	General requirements pertaining to the Designated Representative.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CTG-2, CTG-3	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. **(future requirement)**. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement)**.
Permit Application Shield	§72.32		CTG-2, CTG-3	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CTG-2, CTG-3	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the TEC simple cycle CTGs.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CTG-2, CTG-3	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and (c)		CTG-2, CTG-3	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CTG-2, CTG-3	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CTG-2, CTG-3	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CTG-2, CTG-3	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CTG-2, CTG-3	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CTG-2, CTG-3	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CTG-2, CTG-3	CO_2 continuous monitoring requirements. Appendix G election will be made.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CTG-2, CTG-3	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CTG-2, CTG-3	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CTG-2, CTG-3	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CTG-2, CTG-3	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CTG-2, CTG-3	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CTG-2, CTG-3	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CTG-2, CTG-3	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CTG-2, CTG-3	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CTG-2, CTG-3	Missing data substitution procedure requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CTG-2, CTG-3	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CTG-2, CTG-3	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CTG-2, CTG-3	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CTG-2, CTG-3	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CTG-2, CTG-3	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CTG-2, CTG-3	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CTG-2, CTG-3	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CTG-2, CTG-3	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CTG-2, CTG-3	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CTG-2, CTG-3	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CTG-2, CTG-3	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CTG-2, CTG-3	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CTG-2, CTG-3	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year **(potential future requirement)**.
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		The TEC simple cycle CTGs will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		TEC personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		TEC will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		The TEC simple cycle CTGs will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		TEC personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		TEC personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		TEC personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 11 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 57, 58, 64, 66, 67, 68, 69, 71, 73, 74, 76, 78, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 95, and 96		X		The listed regulations do not contain any requirements which are applicable to the TEC simple cycle CTGs.

Source: ECT, 1999.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempted.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to the TEC simple cycle CTGs.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial contruction permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.2.00, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. **(future requirement)**
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting			X		Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)39., (c), (d), and (e), F.A.C.			CTG-2, CTG-3	NSPS Subpart GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CTG-2, CTG-3	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. **(future requirement)**
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment					
Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants **(future requirement)**.
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports					
Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. **(future requirement)**.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. **Excess emissions for up to four hours in a 24 hour period are specifically requested for the TEC simple cycle CTGs. See Section 2.2 of the PSD permit application for details.**
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to the TEC simple cycle CTGs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. **(potential future requirement)**.
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement).**
Forms and Instructions	62-210.900, F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Project.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CTG-2, CTG-3	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214--Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CTG-2, CTG-3	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation. **(future requirement)**
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CTG-2, CTG-3	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CTG-2, CTG-3	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CTG-2, CTG-3	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CTG-2, CTG-3	Defines permit activation and termination procedures **(potential future requirement)**.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.**[1]		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Project does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to the TEC simple cycle CTGs.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Project is not located in an ozone nonattainment area or an ozone air quality maintenance area.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Project is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Project is not located in a lead non-attainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Project is not located in a PM nonattainment area or a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the TEC simple cycle CTGs.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] - State requirement only; not federally enforceable.

Source: ECT, 1998.

ATTACHMENT A-2

II.E.4—PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Environmental Consulting & Technology, Inc.

ATTACHMENT A-3

III.L.2—FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
<u>Other Characteristics</u>	
Heat content	1,022 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5776
Sulfur content (maximum)	2.0 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: TEC, 1999.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Specific gravity @ 60°F (maximum)	0.876
Viscosity, saybolt (SUS) @ 100°F	
Minimum	40.2
Maximum	32.6
Flash point, °F (minimum)	100
Pour point, °F (minimum)	0
Minimum gross heating value, Btu/gal	
LHV	129,811
HHV	137,600
Water and sediment, percent by volume (maximum)	0.05
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015
Trace constituents, ppm (maximum)	
Lead	1.0
Sodium	1.0
Vanadium	0.5

Note: SUS = Saybolt Universal Seconds.
Btu/gal = British thermal units per gallon.
LHV = lower heating value.
HHV = higher heating value.

Source: TEC, 1992.

ATTACHMENT B—

CTG VENDOR EMISSIONS DATA

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	20.	20.	20.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	183,400.	137,500.	91,700.
Heat Rate (LHV)	Btu/kWh	9,300.	9,950.	11,910.
Heat Cons. (LHV) X 10^6	Btu/h	1,705.6	1,368.1	1,092.1
Exhaust Flow X 10^3	lb/h	3776.	3010.	2473.
Exhaust Temp.	Deg F.	1081.	1111.	1160.
Exhaust Heat (LHV) X 10^6	Btu/h	1017.8	848.9	738.3

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	63.	50.	39.
CO	ppmvd	15.	15.	15.
CO	lb/h	51.	41.	34.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	12.	10.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.91	0.90
Nitrogen	75.06	75.07	75.18
Oxygen	12.56	12.59	12.90
Carbon Dioxide	3.87	3.85	3.71
Water	7.61	7.59	7.31

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	30
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 4 . 1 Opt: N
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TECO - Polk station

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	170,300.	127.700.	85,100.
Heat Rate (LHV)	Btu/kWh	9,370.	10,130.	12,200.
Heat Cons. (LHV) X 10^6	Btu/h	1,595.7	1,293.6	1,038.2
Exhaust Flow X 10^3	lb/h	3518.	2874.	2384.
Exhaust Temp.	Deg F.	1117.	1139.	1184.
Exhaust Heat (LHV) X 10^6	Btu/h	956.6	810.4	708.7

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	59.	47.	37.
CO	ppmvd	15.	15.	15.
CO	lb/h	48.	39.	32.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.88	0.89
Nitrogen	74.38	74.43	74.54
Oxygen	12.38	12.52	12.85
Carbon Dioxide	3.87	3.80	3.65
Water	8.49	8.37	8.07

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 4 . 1 Opt: N

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ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	90.	90.	90.
Fuel Type		Cust Gas	Cust Gas	Cust Gas
Fuel LHV	Btu/lb	20,886	20,886	20,886
Fuel Temperature	Deg F	80	80	80
Output	kW	151,100.	113,300.	75,500.
Heat Rate (LHV)	Btu/kWh	9,720.	10,620.	12,860.
Heat Cons. (LHV) X 10^6	Btu/h	1,468.7	1,203.2	970.9
Exhaust Flow X 10^3	lb/h	3263.	2695.	2262.
Exhaust Temp.	Deg F.	1141.	1166.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	899.5	772.2	676.3

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	54.	44.	35.
CO	ppmvd	15.	15.	15.
CO	lb/h	43.	36.	30.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.87	0.86
Nitrogen	72.32	72.37	72.50
Oxygen	11.96	12.10	12.48
Carbon Dioxide	3.80	3.73	3.56
Water	11.06	10.93	10.60

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	80
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

IPS- version code- 1 . 4 . 1 Opt: N
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ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	20.	20.	20.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	189,400.	142,100.	94,700.
Heat Rate (LHV)	Btu/kWh	10,060.	10,880.	12,730.
Heat Cons. (LHV) X 10^6	Btu/h	1,905.4	1,546.	1,205.5
Exhaust Flow X 10^3	lb/h	3894.	2911.	2430.
Exhaust Temp.	Deg F.	1067.	1184.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	1056.0	900.4	766.3
Water Flow	lb/h	132,150.	102,410.	69,710.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	338.	272.	210.
CO	ppmvd	33.	33.	33.
CO	lb/h	113.	84.	71.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	15.	11.	10.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.85	0.87
Nitrogen	71.82	71.53	72.47
Oxygen	11.17	10.49	11.37
Carbon Dioxide	5.61	6.02	5.60
Water	10.54	11.11	9.70

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	30
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	59.	59.	59.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	178,800.	134,100.	89,400.
Heat Rate (LHV)	Btu/kWh	10,040.	10,880.	12,840.
Heat Cons. (LHV) X 10^6	Btu/h	1,795.2	1,459.	1,147.9
Exhaust Flow X 10^3	lb/h	3662.	2812.	2395.
Exhaust Temp.	Deg F.	1098.	1195.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	996.1	854.1	735.2
Water Flow	lb/h	120,430.	91,300.	62,380.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	319.	257.	200.
CO	ppmvd	33.	33.	33.
CO	lb/h	106.	81.	70.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	14.	11.	9.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.86	0.87
Nitrogen	71.31	71.26	72.21
Oxygen	11.04	10.63	11.59
Carbon Dioxide	5.61	5.88	5.40
Water	11.19	11.37	9.94

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	60
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

ESTIMATED PERFORMANCE PG7241(FA)

Load Condition		BASE	75%	50%
Ambient Temp.	Deg F.	90.	90.	90.
Fuel Type		Dist.	Dist.	Dist.
Fuel LHV	Btu/lb	18,300	18,300	18,300
Fuel Temperature	Deg F	59	59	59
Liquid Fuel H/C Ratio		1.8	1.8	1.8
Output	kW	159,900.	119,900.	79,900.
Heat Rate (LHV)	Btu/kWh	10,210.	11,150.	13,240.
Heat Cons. (LHV) X 10^6	Btu/h	1,632.6	1,336.9	1,057.9
Exhaust Flow X 10^3	lb/h	3375.	2693.	2316.
Exhaust Temp.	Deg F.	1130.	1200.	1200.
Exhaust Heat (LHV) X 10^6	Btu/h	931.9	808.1	698.3
Water Flow	lb/h	91,870.	67,650.	44,800.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	290.	235.	184.
CO	ppmvd	33.	33.	33.
CO	lb/h	97.	77.	67.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	13.	11.	9.
Particulates	lb/h	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

Argon	0.85	0.85	0.85
Nitrogen	70.02	70.24	71.08
Oxygen	10.85	10.77	11.69
Carbon Dioxide	5.50	5.59	5.12
Water	12.79	12.56	11.27

SITE CONDITIONS

Elevation	ft.	143.0
Site Pressure	psia	14.63
Inlet Loss	in Water	4.0
Exhaust Loss	in Water	5.5
Relative Humidity	%	80
Application		7FH2 Hydrogen-Cooled Generator
Combustion System		9/42 DLN Combustor

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

ATTACHMENT C—

CONTROL SYSTEM VENDOR QUOTE

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

January 26, 1999

Sargent & Lundy
ATTN: Paula Scholl

RE: **Sargent and Lundy / Tampa Electric – Polk Station**
GE Fr7FA Simple Cycle Turbine
Oxidation Catalyst Components
High Temperature SCR Catalyst System Components
Engelhard Budgetary Proposal EPB99318

Dear Ms Scholl,

We provide Engelhard Budgetary Proposal EPB99318 for Engelhard **Camet® CO** Oxidation Catalyst System Components and **NOxCAT ZNX™** High Temperature SCR Catalyst system components for the above project. This is per your FAXed request of January 25, 1999.

Our Budgetary Proposal is based on:

- Given data for GE 7EA Gas Turbine operating in simple cycle mode;
- Oxidation Catalysts for 90% CO reduction as noted;
- Catalysts for NOx reduction as noted with ammonia slip of 5 ppmvd@15%O_2;
  - Option 1: NOx reduction from 10.5 ppmvd @ 15% O_2 to 6 ppmvd @ 15% O_2
  - Option 2: NOx reduction from 10.5 ppmvd @ 15% O_2 to 3.5 ppmvd @ 15% O_2
  - Option 3: NOx reduction from 12 ppmvd @ 15% O_2 to 6 ppmvd @ 15% O_2
  - Option 4: NOx reduction from 12 ppmvd @ 15% O_2 to 3.5 ppmvd @ 15% O_2

- Delta P through SCR system - Nominal 3"WG;
- Assumed internally insulated ducts with cross sections at the catalysts as illustrated.
- Scope as noted. Please note that we have assumed horizontal gas flow through the CO / SCR reactor and the use of 28% aqueous ammonia. The system proposed requires the use of an ambient air cooling system to reduce the gas temperature to the SCR catalyst.
- Three (3) Year Performance Guarantee (expected life five to seven years).

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

ENGELHARD CORPORATION
CAMET™ CO CATALYST SYSTEM
NOxCAT ZNX™ HIGH TEMPERATURE SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **CAMET™** metal substrate CO Catalyst System components and the **NOxCAT ZNX™** ceramic substrate SCR system components summarized herein.

Scope of Supply
1. Engelhard **CAMET® CO** and **NOxCAT ZNX™** SCR catalyst in modules;
2. Internal support structures for catalyst modules (frames);
3. Internally insulated reactor ductwork - with stainless steel liner sheets - to house CO catalyst modules, AIG, and SCR Catalyst modules;
4. Ammonia Injection Grid (AIG);
5. AIG manifold with flow control valves ;
6. NH_3 Vaporization / Air dilution skid: 28% Aqueous Ammonia to skid;
7. Ambient air cooling system components as required.

BUDGET PRICES: Per Turbine-	**Option 1**	**Option 2**	**Option 3**	**Option 4**
CO Catalyst System	**$ 885,000**	**$1,075,000**	**$ 960,000**	**$1,100,000**
Replacement CO Modules	**$ 700,000**	**$ 850,000**	**$ 780,000**	**$ 900,000**
SCR Catalyst System	**$2,400,000**	**$3,400,000**	**$2,600,000**	**$3,500,000**
Replacement ZNX Modules	**$1,000,000**	**$1,800,000**	**$1,200,000**	**$2,000,000**

WARRANTY AND GUARANTEE:

Mechanical Warranty: One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.

Performance Guarantee: Three (3) years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings / Documentation - 6 - 8 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details

Operating manuals

Material Delivery 20 - 24 weeks after approval and release for fabrication

SYSTEM DESIGN BASIS:	
Gas Flow from:	GE Fr7FA - with ambient air cooling
Gas Flow:	Assumed Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance data
CO Reduction:	90%
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	See Performance data
NH3 Slip:	5 ppmvd@15%O_2
Pressure Drop through SCR	Nom. 3"WG through ea. catalyst

ENGELHARD

Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

Performance Data

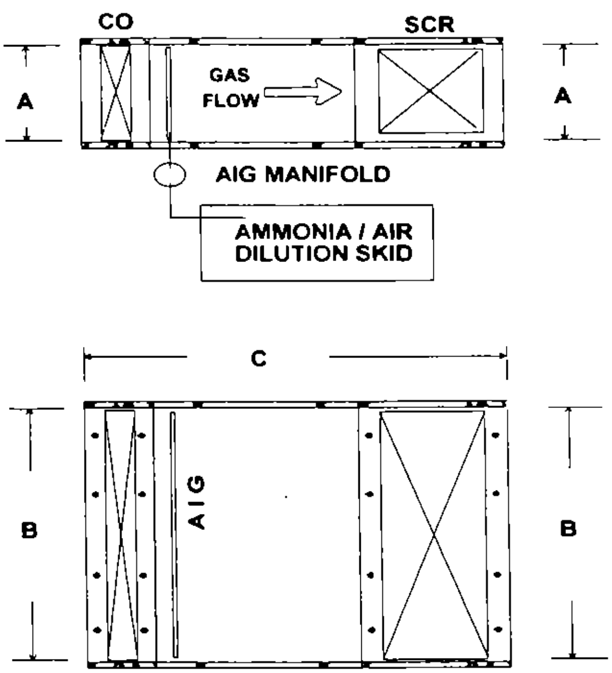
GIVEN / CALCULATED DATA	OPTION 1	OPTION 2	OPTION 3	OPTION 4
AMBIENT	90	90	90	90
LOAD	BASE	BASE	BASE	BASE
TURBINE EXHAUST TEMPERATURE, F	1,140	1,140	1,140	1,140
TURBINE EXHAUST FLOW, lb/hr	3,280,000	3,280,000	3,280,000	3,280,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.19	74.19	74.19	74.19
O2	12.47	12.47	12.47	12.47
CO2	3.80	3.80	3.80	3.80
H2O	8.65	8.65	8.65	8.65
Ar	0.89	0.89	0.89	0.89
AMBIENT AIR FLOW, lb/hr	443,597	443,597	443,597	443,597
TOTAL FLOW - TURBINE EXHAUST + AMBIENT - lb/hr	3,723,597	3,723,597	3,723,597	3,723,597
AMBIENT + EXHAUST GAS ANALYSIS, % VOL. N2	75.02	75.02	75.02	75.02
O2	13.21	13.21	13.21	13.21
CO2	3.35	3.35	3.35	3.35
H2O	7.63	7.63	7.63	7.63
Ar	0.79	0.79	0.79	0.79
CALCULATED AIR + GAS MOL. WT.	28.41	28.41	28.41	28.41
GIVEN: TURBINE CO, ppmvd @ 15% O2	15.0	15.0	15.0	15.0
CALC.: TURBINECO, lb/hr	54.5	54.5	54.5	54.5
GIVEN: TURBINE NOx, ppmvd @ 15% O_2	10.5	10.5	12.0	12.0
CALC.: TURBINE NOx, lb/hr	62.7	62.7	71.6	71.6
CALC.: CO, ppmvd@15%O2 - AT CATALYST FACE	14.4	14.4	14.4	14.4
CALC.: NOx, ppmvd@15%O2 - AT CATALYST FACE	10.1	10.1	11.5	11.5
AMBIENT + EXHAUST GAS TEMP. @ CATALYSTS, F	1,025	1,025	1,025	1,025
DESIGN REQUIREMENTS				
CO CATALYST — CO OUT, ppmvd@15%O2	1.4	1.4	1.4	1.4
SCR CATALYST — NOx OUT, ppmvd@15%O2	6.0	3.5	6.0	3.5
NH3 SLIP, ppmvd@15%O2	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	3"	3"	3"	3"
GUARANTEED PERFORMANCE DATA				
CO CATALYST — CO CONVERSION - % Max.	90.0%	90.0%	90.0%	90.0%
CO OUT, ppmvd@15%O2 - Max.	1.4	1.4	1.4	1.4
CO OUT, lb/hr - Max.	5.5	5.5	5.5	5.5
CO PRESSURE DROP, "WG - Max.	1.7	1.1	1.4	1.0
SCR CATALYST — NOx CONVERSION, % - Min.	42.9%	66.7%	50.0%	70.8%
NOx OUT, lb/hr - Max.	35.8	20.9	35.8	20.9
NOx OUT, ppmvd@15%O2 - Max.	5.8	3.4	5.8	3.4
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	77	96	88	108
NH3 SLIP, ppmvd@15%O2 - Max.	5	5	5	5
SCR PRESSURE DROP, "WG - Max.	3.0	3.0	3.0	3.0

Sargent and Lundy / Tampa Electric - Polk
GE 7FA Simple Cycle Turbine
CAMET® CO Catalyst Systems
ZNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99318
January 26, 1999

The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

Assumed Dimensions / Sketch:

	Option 1
Reactor Width	(A) 49'-3"
Reactor Height	(B) 32'-3"
Reactor Reactor Depth	(C) 15'-0"
	Option 2
Reactor Width	(A) 54'-0"
Reactor Height	(B) 38'-6"
Reactor Reactor Depth	(C) 15'-6"
	Option 3
Reactor Width	(A) 45'-0"
Reactor Height	(B) 40'-0"
Reactor Reactor Depth	(C) 15'-0"
	Option 4
Reactor Width	(A) 57'-3"
Reactor Height	(B) 38'-6"
Reactor Reactor Depth	(C) 16'-0"



Excluded from Scope of Supply:
Ammonia storage and pumping
Any duct transitions to and from reactor
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Any interconnecting field piping or wiring
Utilities
All Monitors

Tampa Electric Company
Polk Station Peaking Unit 2

COST ESTIMATE FOR ADDED SCR - LABOR AND COMMODITY COSTS

Project No. 10456-000
January 29, 1999

Item Description	Comments/Assumptions	Material or Equipment	Quantity	Units	Unit Price matl/equip	Total matl or equip Cost	Unit Labor Rate	Total Manhours	Crew Wage Rate	Total Labor Cost	Total Projected Cost
Ambient air fans	Provide 2 blowers and duct work on each side of the exhaust upstream of silencer to inject cool air.	Fans	2	Ea	25,000.00	$50,000	100	200	41.00	$8,200	$58,200
Foundation for ambient air fans	Assume small support pedestals on 4' thick mat. Each mat plan area estimated at 100 sq. ft. Add 30% for pedestals.	Concrete	39	CY	70.17	$2,700	1.885	73	19.57	$1,400	$4,100
		Reinforcing	3.4	TN	562.00	$1,900	23.1	78	32.03	$2,500	$4,400
		Formwork	416	SF	2.18	$900	0.185	77	26.92	$2,100	$3,000
		Piles	8	Ea	1,000.00	$8,000	5.55	44	70.12	$3,100	$11,100
Ambient air cooling ductwork.	Assume 2 ducts 7' x 7' x 40' long. Use a ductwork weight of 20 psf.	Stiffened plate, A36 material	22.4	TN	1,600.00	$35,800	20	448	65.96	$29,600	$65,400
		Support Steel	5.6	TN	1,600.00	$9,000	20	112	65.96	$7,400	$16,400
	Insulation & Lagging	Mineral Wool	2,240	SF	17.04	$38,200	0.146	327	37.00	$12,100	$50,300
Transition duct after silencer, before SCR.	Assume length of 35' and weight of 40 psf to include extensive turning vanes and lower material properties at high temperatures. Transitions from 25'W x 22'H to 63.5'W x 41.75'H	Stiffened plate	118	TN	1,600.00	$189,200	25	2,957	65.96	$195,000	$384,200
		Support Steel	29.6	TN	1,600.00	$47,300	25	739	65.96	$48,800	$96,100
	Insulation & Lagging	Mineral Wool	5,880	SF	17.04	$100,200	0.146	858	37.00	$31,800	$132,000
SCR & CO Catalyst System	Assume that the reactor dimensions are as follows: 63.5'W x 41.75'H x 16"D.		1	Ea	**See Vendor Quote**		12,000	12,000	62.00	$744,000	$744,000

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Tampa Electric Company
Polk Station Peaking Unit 2

COST ESTIMATE FOR ADDED SCR - LABOR AND COMMODITY COSTS

Project No. 10456-000
January 29, 1999

Item Description	Comments/Assumptions	Material or Equipment	Quantity	Units	Unit Price matl/equip	Total matl or equip Cost	Unit Labor Rate	Total Manhours	Crew Wage Rate	Total Labor Cost	Total Projected Cost
		Support Steel	40	TN	1,600.00	$64,000	25	1,000	65.96	$66,000	$130,000
	Insulation & Lagging	Mineral Wool	3,368	SF	17.04	$57,400	0.146	492	37.00	$18,200	$75,600
Transition duct after SCR, before stack.	Assume length of 40' and weight of 40 psf to include extensive turning vanes and lower material properties at high temperatures. Transitions from 63.5'W x 41.75'H to 18'W x 41.75'H	Stiffened plate	142	TN	1,600.00	$227,700	25	3,558	65.96	$234,700	$462,400
		Support Steel	35.6	TN	1,600.00	$56,900	25	890	65.96	$58,700	$115,600
	Insulation & Lagging	Mineral Wool	7,101	SF	17.04	$121,000	0.146	1,037	37.00	$38,400	$159,400
Expansion joints	Ambient air ducts	Fabric	56	LF	120.00	$6,700	2	112	62.00	$6,900	$13,600
	Between silencer & transition	Fabric	94	LF	120.00	$11,300	2	188	62.00	$11,700	$23,000
	Between transition and stack	Fabric	120	LF	120.00	$14,300	2	239	62.00	$14,800	$29,100
Galleries to access SCR	Platforms and stairs	Steel	3,000	SF	30.00	$90,000	0.380	1,140	65.96	$75,200	$165,200
Foundation under transition ducts and SCR	Assume 4' thick mat, 91' long and 65' wide. Assumed volume includes allowance for small piers/pads for equipment and duct/SCR support on main mat.	Concrete	964	CY	70.17	$67,600	1.885	1,817	19.57	$35,600	$103,200
		Reinforcing	83.4	TN	562.00	$46,900	23.1	1,926	32.03	$61,700	$108,600
		Formwork	1,373	SF	2.18	$3,000	0.185	254	26.92	$6,800	$9,800
		Piles	54	Ea	1,000.00	$54,000	5.55	300	70.12	$21,000	$75,000
	Total Direct Costs					$1,304,000		30,866		$1,735,700	$3,039,700
Engineering Indirects	7% of total direct costs										$212,800

Attachment C-1. Polk Power Station Simple Cycle CTGs - Basis for SCR Capital Costs

Item	($)	OAQPS Factor	Basis
A. Direct Costs			
Purchased Equipment	4,035,000	A	Engelhard quote of \$3,400,000 + Sargent & Lundy estimate for exhaust stream cooling equipment + cost of NH_3 storage tank. Engelhard Quote = \$3,400,000 Sargent & Lundy Estimate = \$50,000 + 35,800 + 169,000 + 227,700 + 6,700 + 11,300 + 14,300 + 90,000 = \$605,000 NH_3 storage tank = \$30,000 Total SCR System = \$3,400,000 + \$605,000 + \$30,000 = \$4,035,000
Sales Tax	242,100	0.06 x A	Purchased Equipment x 6% sales tax Sales Tax = \$4,035,000 x (0.06) = \$242,100
Freight	201,750	0.05 x A	Purchased Equipment x OAQPS Freight Factor of 0.05 Sales Tax = \$4,035,000 x (0.05) = \$201,750
Subtotal Purchased Equipment	4,478,850	B	Sum of Purchased Equipment + Sales Tax + Freight Subtotal Purchased Equipment = \$4,035,000 + \$242,100 + \$201,750 = \$4,478,850
Subtotal Installation Cost	1,343,655	0.30 x B	Subtotal Purchased Equipment x OAQPS Installation Cost Factor of 0.30 OAQPS Installation Cost Factor = (0.08 + 0.14 + 0.04 + 0.02 + 0.01 + 0.01) = 0.30 Subtotal Installation Cost = \$4,478,850 x 0.30 = \$1,343,655
Subtotal Direct Costs	5,822,505		Subtotal Purchased Equipment + Subtotal Installation Cost Subtotal Direct Costs = \$4,478,850 + \$1,343,655 = \$5,822,505
B. Indirect Costs			
Subtotal Indirect Costs	1,388,444	0.31 x B	Subtotal Purchased Equipment x OAQPS Indirect Cost Factor of 0.31 OAQPS Indirect Cost Factor = (0.10 + 0.05 + 0.10 + 0.02 + 0.01 + 0.03) = 0.31 Subtotal Indirect Costs = \$4,478,850 x 0.31 = \$1,388,444
Total Capital Investment	**7,210,949**	TCI	Subtotal Direct Cost + Subtotal Indirect Cost Total Capital Investment = \$5,822,505 + \$1,388,444 = \$7,210,949

Attachment C-2. Polk Power Station Simple Cycle CTGs - Basis for SCR Annual Operating Costs (Page 1 of 4)

Item	($)	OAQPS Factor	Basis
A. Direct Costs			
Operator Labor	7,227	A	0.50 hrs/shift x 3 shifts/day x 219 dys/yr x $22.00/hr Operator Labor = (0.50) x (3) x (219) x (22.00) = $7,227
Supervisor Labor	1,084	0.15 x A	Operator Labor x OAQPS Supervisor Labor Factor of 0.15 Supervisor Labor = $7,227 x 0.15 = $1,084
Maintenance Labor	7,227	B	0.5 hrs/shift x 3 shifts/day x 219 dys/yr x $22.00/hr Maintenance Labor = (0.5) x (3) x (219) x (22.00) = $7,227
Maintenance Material	7,227	1.0 x B	Maintenance Labor x OAQPS Supervisor Labor Factor of 1.0 Maintenance Materials = $7,227 x 1.0 = $7,227
Subtotal Labor and Materials	22,765	C	Operator Labor + Supervisor Labor + Maintenance Labor + Maintenance Materials Subtotal Labor and Materials = $7,227 + $1,084 + $7,227 + $7,227 = $22,765
Catalyst Replacement Costs	2,088,000		Engelhard quote of $1,800,000 + sales tax + freight + disposal and associated expenses Catalyst Cost = $1,800,000 Sales Tax = $1,800,000 x 0.06 = $108,000 Freight = $1,800,000 x 0.05 = $90,000 Labor and Associated Expenses = $90,000 Total Catalyst Replacement Cost = $1,800,000 + $108,000 + $90,000 + $90,000 Total Catalyst Replacement Cost = $2,088,000

Attachment C-2. Polk Power Station Simple Cycle CTGs - Basis for SCR Annual Operating Costs (Page 2 of 4)

Item	($)	OAQPS Factor	Basis
Annualized Catalyst Replacement Costs	544,491		Total Catalyst Replacement Cost x Capital Recovery Factor (CRF) CFR = $[i \times (1 + i)^n] / [(1+i)^n - 1]$ i = annual pretax marginal rate of return on pivate investment = 9.55% (0.0955) for TEC n = frequency of catalyst replacement = 5 years (Engelhard estimate) CFR = $[0.0955 \times (1+0.0955)^5] / [(1+0.0955)^5 - 1]$ = 0.2608 Annualized Catalyst Replacement Cost = $2,088,000 x 0.2608 = $544,491
Electricity Cost	17,722		Power for NH_3 Fan and Pump + Power to Vaporize Liquid NH_3 Power for NH_3 Fan and Pump = 5 kW x $0.040 kWh x 5,256 hrs/yr = $1,051 Power to Vaporize Liquid NH_3 = 2 kW per lb NH_3 = [(2 kW) x (0.28 lb NH_3 / lb $NH_{3-aq.}$) x (141.6 lb $NH_{3-aq.}$/hr)] x $0.040 kWh x 5,256 hrs/yr = $16,671 Electricity Cost = $1,051 + $16,671 = $17,722
Aqueous Ammonia Cost	119,092		Aqueous NH_3 = $320/ton; 28 weight % NH_3 solution; 1:1 molar ratio of NH_3 to NO_x NO_x = 90% NO + 10% NO_2, by volume; SCR Control Efficiency = 70.83 % Molecular Weight (MW) NO = 30 lb/mole; MW NO_2 = 46 lb/mole MW NO_x = (.9 x 30) + (.1 x 46) = 31.6 lb NO_x / mole NO_x NO_x Controlled = 73.7 lb/hr Aqueous NH_3 Usage = (NO_x lb/hr) x (1 mole NH_3 / 1 mole NO_x) x (17 lb NH_3 / mole NH_3) x (mole NO_x / 31.6 lb NO_x) x (100 lb $NH_{3-aq.}$ / 28 lb NH_3) x (5,256 hrs/yr) x (1 ton/2,000 lb) = (73.7) x (1/1) x (17) x (1/31.6) x (100/28) x (5,256) x (1/2,000) = 372.2 ton/yr Aqueous NH_3 Cost = 372.2 ton/yr x $320/ton = $119,092
Subtotal Raw Materials and Utilities	136,815		Electricity Cost + Aqueous Ammonia Cost Subtotal Raw Materials and Utilities = $17,722 + $119,092 = $136,815

Attachment C-2. Polk Power Station Simple Cycle CTGs - Basis for SCR Annual Operating Costs (Page 3 of 4)

Item	($)	OAQPS Factor	Basis
Energy Penalties			
Turbine Backpressure	208,138		Turbine Backpressure Penalty = 0.2% per 1.0 inch H_2O backpressure (GE) Turbine Backpressure = 3.0 inch H20 (Engelhard); CT Power Output = 165,000 kW Power Cost = $0.040 kW; Annual Hours = 5,256 hrs/yr Turbine Backpressure Penalty = (3.0) x (0.2/100) x (165,000 kW) x (5,256 hrs/yr) x ($0.040/kWh) Turbine Backpressure Penalty = $208,138
Subtotal Direct Costs	912,209		Subtotal Direct Costs = Subtotal Labor and Materials + Annualized Catalyst Replacemen Cost + Subtotal Raw Materials and Utilities + Turbine Backpressure Subtotal Direct Costs = $22,765 + $544,491 + $136,815 + $208,138 Subtotal Direct Costs = $912,209
B. Indirect Costs			
Overhead	13,659	0.60 x C	Subtotal Labor and Materials x OAQPS Overhead Cost Factor Overhead = $22,765 x 0.60 = $13,659
Administrative Charges	144,219	0.02 x TCI	Total Capital Investment x OAQPS Administrative Charges Factor Administrative Charges = $7,210,949 x 0.02 = $144,219
Property Taxes	72,110	0.01 x TCI	Total Capital Investment x OAQPS Property Tax Factor Property Taxes = $7,210,949 x 0.01 = $72,110
Insurance	72,110	0.01 x TCI	Total Capital Investment x OAQPS Insurance Factor Insurance = $7,210,949 x 0.01 = $72,110

Attachment C-2. Polk Power Station Simple Cycle CTGs - Basis for SCR Annual Operating Costs (Page 4 of 4)

Item	($)	OAQPS Factor	Basis
Capital Recovery	667,855		Capital Recovery = (TCI - Initial Catalyst Cost) x CRF TCI = \$7,210,949; Initial Catalyst Cost = \$1,998,000 $CFR = [i \times (1 + i)^n] / [(1+i)^n - 1]$ i = annual pretax marginal rate of return on pivate investment = 9.55% (0.0955) for TEC n = control system life = 15 years $CFR = [0.0955 \times (1+0.0955)^{15}] / [(1+0.0955)^{15} - 1] =$ 0.1281 Capital Recovery = (\$7,210,949 - \$1,998,000) x 0.1281 = \$667,855
Subtotal Indirect Costs	969,952		Subtotal Indirect Costs = Overhead + Administrative Charges + Property Taxes + Insurance + Capital Recovery Subtotal Indirect Costs = \$13,659 + \$144,219 + \$72,110 + \$72,110 + \$667,855 Subtotal Direct Costs = \$969,952
Total Annual Cost	1,882,161		Total Annual Cost = Subtotal Direct Costs + Subtotal Indirect Costs Total Annual Cost = \$912,209 + \$969,952 Total Annual Cost = \$1,882,161
Cost Effectivness	**9,717**		Cost Effectiveness = Total Annual Cost / tons NO_x Controlled Tons NO_x Controlled (Per CTG) = 193.7 Tons NO_x Controlled (Two CTGs) = 2 x 193.7 = 387.4 Total Annual Cost (Per CTG) = \$1,882,161 Total Annual Cost (Two CTGs) = 2 x \$1,882,161 = \$3,764,322 Cost Effectiveness = \$3,764,322 / 387.4 tons = \$9,717

ATTACHMENT D—

EMISSION RATE CALCULATIONS

Table 1. TEC Polk Power Station, CT-2 and CT-3
CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	CT-2	CT-3	Natural Gas Firing	Fuel Oil Firing
1	20	100	X	X	X	X
2	20	75	X	X	X	X
3	20	50	X	X	X	X
4	59	100	X	X	X	X
5	59	75	X	X	X	X
6	59	50	X	X	X	X
7	90	100	X	X	X	X
8	90	75	X	X	X	X
9	90	50	X	X	X	X

Sources: TEC, 1999.
ECT, 1999.

Table 2. TEC Polk Power Station, CT-2 and CT-3
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)
20	1	100	10.1	1.28	9.8	1.24	1.1	0.14
	2	75	9.9	1.25	7.9	0.99	0.9	0.11
	3	50	9.7	1.23	6.3	0.79	0.7	0.09
59	4	100	10.1	1.27	9.2	1.16	1.1	0.13
	5	75	9.9	1.24	7.5	0.94	0.9	0.11
	6	50	9.7	1.22	6.0	0.75	0.7	0.09
90	7	100	10.0	1.26	8.5	1.07	1.0	0.12
	8	75	9.8	1.23	6.9	0.87	0.8	0.10
	9	50	9.6	1.22	5.6	0.71	0.6	0.08
		Maximums	10.1	1.28	9.8	1.24	1.1	0.14

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[4]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[4]	CO (lb/hr)	CO (g/sec)	VOC[5] (ppmvd)[4]	VOC[5] (lb/hr)	VOC[5] (g/sec)
20	1	100	10.5	73.5	9.26	12.1	51.0	6.43	6.1	15.0	1.89
	2	75	10.5	58.3	7.35	12.2	41.0	5.17	6.1	12.0	1.51
	3	50	10.5	45.5	5.73	12.7	34.0	4.28	6.4	10.0	1.26
59	4	100	10.5	68.8	8.67	12.0	48.0	6.05	6.1	14.0	1.76
	5	75	10.5	54.8	6.91	12.2	39.0	4.91	6.2	11.0	1.39
	6	50	10.5	43.2	5.44	12.8	32.0	4.03	6.5	9.0	1.13
90	7	100	10.5	63.0	7.94	11.9	43.0	5.42	6.2	13.0	1.64
	8	75	10.5	51.3	6.47	12.1	36.0	4.54	6.3	11.0	1.39
	9	50	10.5	40.8	5.15	12.8	30.0	3.78	6.7	9.0	1.13
		Maximums	10.5	73.5	9.26	12.8	51.0	6.43	6.7	15.0	1.89

1 Includes sulfuric acid mist.
2 Based on natural gas sulfur content of 2.0 gr/100 ft^3.
3 Based on 7.5% conversion of SO_2 to H_2SO_4.
4 Corrected to 15% O_2.
5 Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1999.
GE, 1998.

Table 3. TEC Polk Power Station Unit, CT-2 and CT-3
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

Temp. (°F)	Case	Load (%)	PM/PM10[1] (lb/hr)	PM/PM10[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)
20	1	100	27.0	3.40	104.1	13.12	12.0	1.51
	2	75	20.7	2.61	84.5	10.64	9.7	1.22
	3	50	17.6	2.21	65.9	8.30	7.6	0.95
59	4	100	25.3	3.18	98.1	12.36	11.3	1.42
	5	75	20.2	2.54	79.7	10.05	9.2	1.15
	6	50	16.2	2.04	62.7	7.90	7.2	0.91
90	7	100	23.2	2.93	89.2	11.24	10.2	1.29
	8	75	19.4	2.44	73.1	9.20	8.4	1.06
	9	50	15.6	1.97	57.8	7.28	6.6	0.84
		Maximums	**27.0**	**3.40**	**104.1**	**13.12**	**12.0**	**1.51**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[4]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[4]	CO (lb/hr)	CO (g/sec)	VOC[5] (ppmvd)[4]	VOC[5] (lb/hr)	VOC[5] (g/sec)
20	1	100	42.0	338.0	42.59	23.1	113.0	14.24	5.5	15.0	1.89
	2	75	42.0	272.0	34.27	21.4	84.0	10.58	5.1	11.0	1.39
	3	50	42.0	210.0	26.46	23.4	71.0	8.95	5.5	10.0	1.26
59	4	100	42.0	319.0	40.19	23.0	106.0	13.36	5.5	14.0	1.76
	5	75	42.0	257.0	32.38	21.9	81.0	10.21	5.2	11.0	1.39
	6	50	42.0	200.0	25.20	24.2	70.0	8.82	5.7	9.0	1.13
90	7	100	42.0	290.0	36.54	23.0	97.0	12.22	5.6	13.0	1.64
	8	75	42.0	235.0	29.61	22.7	77.0	9.70	5.5	11.0	1.39
	9	50	42.0	184.0	23.18	25.2	67.0	8.44	6.0	9.0	1.13
		Maximums	**42.0**	**338.0**	**42.59**	**25.2**	**113.0**	**14.24**	**6.0**	**15.0**	**1.89**

[1] Includes sulfuric acid mist.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] Corrected to 15% O_2.
[5] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 1999.
GE, 1998.

Table 4. TEC Polk Power Station Unit, CT-2 and CT-3
CT Emission Rates - General Electric 7241FA CT (Per CT)
Natural Gas-Firing: Noncriteria Pollutants

Maximum Hourly Heat Input: (Case 1)	1,984	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,772	10^6 Btu/hr
Maximum Annual Hours:	4,380	hrs/yr

Pollutant	Emission Factor ($lb/10^6$ Btu)	Emission Factor Reference	Emission Rates (lb/hr)	Emission Rates (ton/yr)
Benzene	1.40E-06	1	2.78E-03	5.43E-03
Dioxins/Furans	1.20E-12	2	2.38E-09	4.66E-09
Formaldehyde	2.90E-05	1	5.75E-02	1.13E-01
Mercury	7.80E-10	3	1.55E-06	3.03E-06
Naphthalene	6.70E-07	1	1.33E-03	2.60E-03
Polycyclic Organic Matter	5.00E-08	1	9.92E-05	1.94E-04
Toluene	1.02E-05	1	2.02E-02	3.96E-02

Emission Factor References:
1 - EPA Electric Utility Hazardous Air Pollutant Study, Final Report, Table A-6, February 1998.
2 - EPRI Synthesis Report, November 1994.
3 - Florida Coordinating Group (FCG), 1995.

Source: ECT, 1999.

Table 5. TEC Polk Power Station Unit, CT-2 and CT-3
CT Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing: Noncriteria Pollutants

Maximum Hourly Heat Input: (Case 1)	2,066	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,947	10^6 Btu/hr
Maximum Annual Hours:	876	hrs/yr

Pollutant	Emission Factor (lb/10^6 Btu)	Emission Factor Reference	Emission Rates (lb/hr)	(ton/yr)
Acetaldehyde	8.20E-06	1	1.69E-02	6.99E-03
Antimony	2.20E-05	2	4.55E-02	1.88E-02
Arsenic	4.90E-06	2	1.01E-02	4.18E-03
Benzene	1.40E-06	1	2.89E-03	1.19E-03
Beryllium	3.30E-07	2	6.82E-04	2.81E-04
Cadmium	4.20E-06	2	8.68E-03	3.58E-03
Chromium	4.70E-05	2	9.71E-02	4.01E-02
Cobalt	9.10E-06	2	1.88E-02	7.76E-03
Dioxins/Furans	1.15E-10	1	2.38E-07	9.81E-08
Ethylbenzene	4.90E-07	1	1.01E-03	4.18E-04
Formaldehyde	3.00E-05	1	6.20E-02	2.56E-02
Hydrogen Chloride	2.48E-03	3	5.12E+00	2.11E+00
Hydrogen Fluoride	2.66E-04	3	5.50E-01	2.27E-01
Lead	5.80E-05	2	1.20E-01	4.95E-02
Manganese	3.40E-04	2	7.02E-01	2.90E-01
Methyl Chloroform	7.60E-06	1	1.57E-02	6.48E-03
Methylene Chloride	3.23E-05	1	6.66E-02	2.75E-02
Mercury	9.10E-07	2	1.88E-03	7.76E-04
Naphthalene	3.40E-07	1	7.02E-04	2.90E-04
Nickel	1.20E-03	2	2.48E+00	1.02E+00
Phenol	2.43E-05	1	5.02E-02	2.07E-02
Phosphorus	3.00E-04	2	6.20E-01	2.56E-01
Polycyclic Organic Matter	6.74E-07	1	1.39E-03	5.75E-04
Selenium	5.30E-06	2	1.09E-02	4.52E-03
Tetrachloroethylene	5.50E-07	2	1.14E-03	4.69E-04
Toluene	8.00E-06	1	1.65E-02	6.82E-03
Vinyl Acetate	5.15E-06	1	1.06E-02	4.39E-03
Xylenes	2.19E-06	1	4.52E-03	1.87E-03

Emission Factor References:

1 - EPA Electric Utility Hazardous Air Pollutant Study, Final Report, Table A-5, February 1998.

2 - EPA AP-42 Emission Factors, Table 3.1-4., October 1996.

3 - EPA AP-42 Emission Factors, Table 1.3-10., October 1996.

Source: ECT, 1999.

Table 6. TEC Polk Power Station, CT-2 and CT-3
CT Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-2	4 - NG	4,380	68.8	150.7	48.0	105.1	14.0	30.7
CT-3	4 - NG	4,380	68.8	150.7	48.0	105.1	14.0	30.7
CT-2	4 - Oil	876	319.0	139.7	106.0	46.4	14.0	6.1
CT-3	4 - Oil	876	319.0	139.7	106.0	46.4	14.0	6.1
		Totals	**N/A**	**580.9**	**N/A**	**303.1**	**N/A**	**73.6**

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			PM/PM_{10}		SO_2		H_2SO_4	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CT-2	4 - NG	4,380	10.1	22.0	9.2	20.2	1.06	2.3
CT-3	4 - NG	4,380	10.1	22.0	9.2	20.2	1.06	2.3
CT-2	4 - Oil	876	25.3	11.1	98.1	43.0	11.27	4.9
CT-3	4 - Oil	876	25.3	11.1	98.1	43.0	11.27	4.9
		Totals	**N/A**	**66.2**	**N/A**	**126.3**	**N/A**	**14.5**

1. CT-2 and CT-3 operating with natural gas-firing at a 50% capacity factor; 4,380 hours/year at base load (Case 4
2. CT-2 and CT-3 operating with fuel oil-firing at a 10% capacity factor; 876 hours/year at base load (Case 4).
3. SO_2 and H_2SO_4 rates based on natural gas sulfur content of 2.0 gr/100 ft^3 and 7.5% conversion of SO_2 to H_2SO
4. SO_2 and H_2SO_4 rates based on fuel oil sulfur content of 0.05 wt. percent and 7.5% conversion of SO_2 to H_2SO_4.

Sources: GE, 1998.
ECT, 1999.
TEC, 1999.

Table 7. TEC Polk Power Station, CT-2 and CT-3
General Electric 7241FA CT
NSPS GG NO_x Limits

Fuel	7241FA Gas Turbine ISO Heat Rate		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,370	9.886	0.0	109.2
Distillate	10,040	10.593	0.0	102.0

Sources: ECT, 1999.
GE, 1998.

Table 8.A. TEC Polk Power Station, CT-2 and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.89	0.87	0.91	0.88	0.87	0.90	0.89	0.86
N_2	28.016	75.06	74.38	72.32	75.07	74.43	72.37	75.18	74.54	72.50
O_2	32.000	12.56	12.38	11.96	12.59	12.52	12.10	12.90	12.85	12.48
CO_2	44.010	3.87	3.87	3.80	3.85	3.80	3.73	3.71	3.65	3.56
H_2O	17.008	7.61	8.49	11.06	7.59	8.37	10.93	7.31	8.07	10.60
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.00	100.01	100.01	100.01	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.41	28.30	27.99	28.41	28.31	28.00	28.43	28.33	28.02
Exhaust Flow (lb/sec)		1,048.89	977.22	906.39	836.11	798.33	748.61	686.94	662.22	628.33
Exhaust Temp. (°F)		1,081	1,117	1,141	1,111	1,139	1,166	1,160	1,184	1,200
(K)		856	876	889	873	888	903	900	913	922
Exhaust O_2 (Vol %, Dry)		13.59	13.53	13.45	13.62	13.66	13.58	13.92	13.98	13.96

Sources: ECT, 1999.
GE, 1998.

Table 8.B. TEC Polk Power Station, CT-2 and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft³/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	**1**	**4**	**7**	**2**	**5**	**8**	**3**	**6**	**9**
ACFM	2,491,429	2,384,051	2,270,019	2,024,406	1,974,549	1,903,746	1,714,105	1,682,606	1,629,943
Velocity (fps)	63.3	60.5	57.6	51.4	50.1	48.3	43.5	42.7	41.4
Velocity (m/s)	19.3	18.4	17.6	15.7	15.3	14.7	13.3	13.0	12.6
SCFM, Dry'	788,670	730,443	665,839	628,745	597,436	550,622	517,832	496,789	463,485
ACFM (15% O_2, Dry)	2,849,980	2,725,734	2,550,293	2,307,030	2,219,082	2,102,390	1,880,347	1,814,753	1,714,092

Sources: ECT, 1999.
GE, 1998.

Table 9.A. TEC Polk Power Station, CT-2 and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %								
Component	MW (lb/mole)	100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.87	0.85	0.85	0.85	0.86	0.85	0.87	0.87	0.85
N_2	28.016	71.82	71.31	70.02	71.53	71.26	70.24	72.47	72.21	71.08
O_2	32.000	11.17	11.04	10.85	10.49	10.63	10.77	11.37	11.59	11.69
CO_2	44.010	5.61	5.61	5.50	6.02	5.88	5.59	5.60	5.40	5.12
H_2O	17.008	10.54	11.19	12.79	11.11	11.37	12.56	9.70	9.94	11.27
SO_2	64.066	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO	28.010	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HC (CH_4)	16.042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NO	30.008	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Totals	100.01	100.00	100.01	100.00	100.00	100.01	100.01	100.01	100.01
Exhaust MW (lb/mole)		28.30	28.22	28.02	28.28	28.23	28.06	28.40	28.35	28.16
Exhaust Flow (lb/sec)		1,081.67	1,017.22	937.50	808.61	781.11	748.06	675.00	665.28	643.33
Exhaust Temp. (°F)		1,067	1,098	1,130	1,184	1,195	1,200	1,200	1,200	1,200
(K)		848	865	883	913	919	922	922	922	922
Exhaust O_2 (Vol %, Dry)		12.49	12.43	12.44	11.80	11.99	12.32	12.59	12.87	13.17

Sources: ECT, 1999.
GE, 1998.

Table 9.B. TEC Polk Power Station, CT-2 and CT-3
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	2,555,005	2,458,676	2,328,904	2,058,509	2,004,944	1,937,579	1,727,258	1,705,360	1,660,210
Velocity (fps)	64.9	62.4	59.1	52.3	50.9	49.2	43.9	43.3	42.2
Velocity (m/s)	19.8	19.0	18.0	15.9	15.5	15.0	13.4	13.2	12.8
SCFM, Dry'	790,343	739,996	674,458	587,676	566,916	538,884	496,102	488,511	468,554
ACFM (15% O_2, Dry)	3,259,640	3,134,307	2,911,876	2,821,905	2,682,434	2,464,653	2,196,457	2,090,523	1,928,817

Sources: ECT, 1999.
GE, 1998.

Table 10. TEC Polk Power Station, CT-2 and CT-3
CT Fuel Flow Rate Data - General Electric 7241FA CT (Per CT)

A. Natural Gas-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV (MMBtu/hr)	1,894	1,772	1,631	1,519	1,437	1,336	1,213	1,153	1,078
Fuel Rate (lb/hr)	81,662	76,400	70,320	65,503	61,936	57,608	52,289	49,708	46,486
Fuel Rate (lb/sec)	22.684	21.222	19.533	18.195	17.205	16.002	14.525	13.808	12.913

B. Distillate Fuel Oil-Firing

	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV (MMBtu/hr)	2,066	1,947	1,770	1,677	1,582	1,450	1,307	1,245	1,147
Fuel Rate (lb/hr)	104,120	98,098	89,213	84,481	79,727	73,055	65,874	62,727	57,809
Fuel Rate (lb/sec)	28.922	27.250	24.781	23.467	22.146	20.293	18.298	17.424	16.058

Sources: ECT, 1999.
GE, 1998.

ATTACHMENT E—

DISPERSION MODELING FILES

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