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BUREAU OF AIR REGULATION

October 17, 2005

Mr. Jeff Koerner
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Via FedEx
Airbill No. 7917 5786 3925

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

Via Fed Ex
Airbill No. 7924 1316 5803

Re: Tampa Electric Company
Polk Power Station
Polk Unit 4 & 5
Construction Permit Application & Request of Modification
PPSA No. PA 92-32

Dear Mr. Koerner and Oven:

Tampa Electric Company (TEC) intends to construct and operate two General Electric (GE) 7F combustion turbines at its Polk Power Station facility and hereby requests a construction permit and a modification of the Site Certification for the Polk Power Station (PA 92-32), pursuant to Section 403.516(1)(b), Florida Statutes. The Siting Board issued the certification for this facility in January 1994, authorizing the construction and operation of the first phase of an 1150 MW capacity facility, which was Polk Unit 1, a gasification unit. The second phase involved the addition of two dual fuel fired GE 7F turbines operated in simple cycle mode, Polk Units 2 and 3. Phase three will include two new GE 7F combustion turbines, which will also be operated in simple cycle mode, Polk Units 4 and 5. TEC has identified the need to obtain an air construction permit and the modification of the existing Conditions of Certification (COC) to incorporate this change.

It is intended that the modifications related to Polk Unit 4 and 5 will be resolved by incorporating the conditions of the separately issued Prevention of Significant Deterioration (PSD) permit that is needed to construct these units. Once the conditions in the new PSD permit are agreed on, TEC will supplement this request to include the new PSD condition language into a new section of the current COC addressing the third phase of the build-out of this site.

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P. O. BOX 111 TAMPA, FL 33601-0111

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OUTSIDE HILLSBOROUGH COUNTY 1 (888) 223-0800

Enclosed with this letter to Mr. Koerner are four (4) signed and sealed copies of TEC's permit application, as well as the Electronic Submission of Application (ELSA), for the construction of these two new simple-cycle combustion turbines at the Polk Power Station. One (1) signed and sealed copy of TEC's permit application and the ELSA is also being sent to Mr. Oven. A check made payable to the Florida Department of Environmental Protection in the amount of $10,000 dollars is enclosed to cover the modification fee per 62-17.293(c), F.A.C. Copies of the attached permit application (with the exception of the associated electronic files) and the modification request are being distributed to all "Parties to the Proceedings" concurrent with this submittal.

TEC appreciates the Departments timely review and processing of the air construction permit application and this modification. If you should have any questions, please feel free to call Raiza Calderon or me at (813) 228-4369.

Sincerely,

Byron T. Burrows, P.E.
Manager - Air Programs
Environmental, Health & Safety

EA/rlk/RC206

Enclosures

c/enc: Joel Smolen, FDEP SW
Bob Soich, FDEP SW
All parties of record (list attached)

POLK POWER STATION

SIMPLE-CYCLE COMBUSTION TURBINES UNITS 4 AND 5

APPLICATION FOR AIR CONSTRUCTION PERMIT

Prepared for:

TECO
TAMPA ELECTRIC
Tampa, Florida

Prepared by:

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

ECT No. 051095-0100

October 2005

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued, Page 2 of 4)

TABLE OF CONTENTS
(Continued, Page 3 of 4)

TABLE OF CONTENTS
(Continued, Page 4 of 4)

LIST OF TABLES

LIST OF TABLES
(Continued, Page 2 of 3)

LIST OF TABLES
(Continued, Page 3 of 3)

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) plans to install two additional simple-cycle combustion turbine (SCCT) generators at its existing Polk Power Station (PPS) located in Polk County, Florida. The PPS 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 existing PPS coal gasification facility consists of solid fuel handling facilities, a solid fuel gasification system, one nominal 260-megawatt (MW) combined-cycle combustion turbine (designated as Unit 1) fired with syngas or distillate fuel oil, an auxiliary boiler, a sulfuric acid (H_2SO_4) plant, slag handling systems, two nominal 165-MW simple-cycle combustion turbine generators (CTGs) (designated as Units 2 and 3), and ancillary support equipment. Operation of the existing PPS coal gasification facility emission sources is currently authorized by Title V Final Permit Revision No. 1050233-016-AV, which was issued with an effective date of January 1, 2005, and expires on December 31, 2009.

TEC is planning to construct and operate two additional simple-cycle CTGs at the PPS. The PPS simple-cycle CTG project will consist of two, nominal 165-MW CTGs (designated as Units 4 and 5) 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 (equivalent to 4,380 hours per year [hr/yr] at baseload) and 8.6 (equivalent to 750 hr/yr at baseload) 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.

Units 4 and 5 will be located in an attainment area and will have nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), particulate matter equal to or less than 10 micrometers (PM_{10}), sulfur dioxide (SO_2), and H_2SO_4 mist emissions increases in excess of 40, 100, 25, 15, 40, and 7 tons per year (tpy), respectively. Consequently, Units 4 and 5 qualify as a major modification to an existing major facility and are subject to the PSD new source review (NSR) requirements of Rule 62-212.400, F.A.C., for NO_x, CO, PM, PM_{10}, SO_2, and H_2SO_4 mist. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP Prevention of Significant Deterioration (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 provides an assessment of impacts on the Chassahowitzka National Wildlife Refuge (NWR) Class I area.
- Section 11.0 lists the references used in preparing this report.

Appendices A and B provide the FDEP Application for Air Permit—Long Form and emission rate calculations, respectively. All dispersion modeling input and output files for the ambient impact analyses are provided in Appendix C. A proposed air construction permit for Units 4 and 5 is provided in Appendix D.

1.2 SUMMARY

The PPS simple-cycle CTG 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 Units 4 and 5 is April 2006. The planned initial date of commencement of operation is May 2007.

Based on an evaluation of anticipated worst-case annual operating scenarios, Units 4 and 5 will have the potential to emit 540.7 tpy of NO_x, 226.8 tpy of CO, 104.3 tpy of PM/PM_{10}, 117.9 tpy of SO_2, and 17.7 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, Units 4 and 5 will potentially emit 13.5 tpy of 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, 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}. Units 4 and 5 will utilize dry low-NO_x (DLN) burner technology 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 CO BACT for Units 4 and 5. At baseload

operation during natural gas and distillate fuel oil firing, Units 4 and 5 CO exhaust concentrations are projected to be 9.0 and 20.0 parts per million by volume dry (ppmvd), respectively. These concentrations are consistent with prior FDEP BACT determinations for simple-cycle CTGs. Cost effectiveness of a CO oxidation catalyst control system was determined to be $6,203 per ton of CO using the FDEP recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of $8,990 per ton of CO controlled. Because these costs exceed 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 Units 4 and 5 during natural gas firing. For all normal operating loads, the NO_x exhaust concentration will not exceed 10.5 ppmvd, corrected to 15-percent oxygen. 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 $10,807 per ton of NO_x using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of $15,760 per ton of NO_x controlled. Because these costs exceed values previously 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 NO_x exhaust concentration to 42 ppmvd, corrected to 15-percent oxygen. 9.00 / 15 Const
- Units 4 and 5 are projected to emit NO_x, CO, PM/PM_{10}, SO_2, 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 Unit 4 and 5 project qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemp- above PSD Levels Both below ambient monitoring Requirement

tion 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 multi-source 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, Units 4 and 5 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 PPS is presently not a major source of hazardous air pollutants (HAPs). The addition of Units 4 and 5 will not change the status of the PPS as a non-major HAP source. Accordingly, Units 4 and 5 will not be subject to any maximum achievable control technology (MACT) requirements.
- The nearest PSD Class I area (Chassahowitzka NWR) 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

Proposed Units 4 and 5 will be located at the existing TEC PPS. The PPS 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 provides portions of a U.S. Geological Survey (USGS) topographical map showing the PPS 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.

Units 4 and 5 will operate at annual capacity factors up to 50 and 8.6 percent for natural gas and oil firing, respectively. At baseload operation, these annual capacity factors are equivalent to 4,380 and 750 hr/yr for natural gas and oil firing, respectively. Annual CTG operating hours will increase with lower load operations.

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 DLN combustors (natural gas firing) and water injection (distillate fuel oil firing) for control of NO_x; good combustion practices for abatement of CO and VOCs; and use of clean, low-sulfur, low-ash natural gas and distillate fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

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

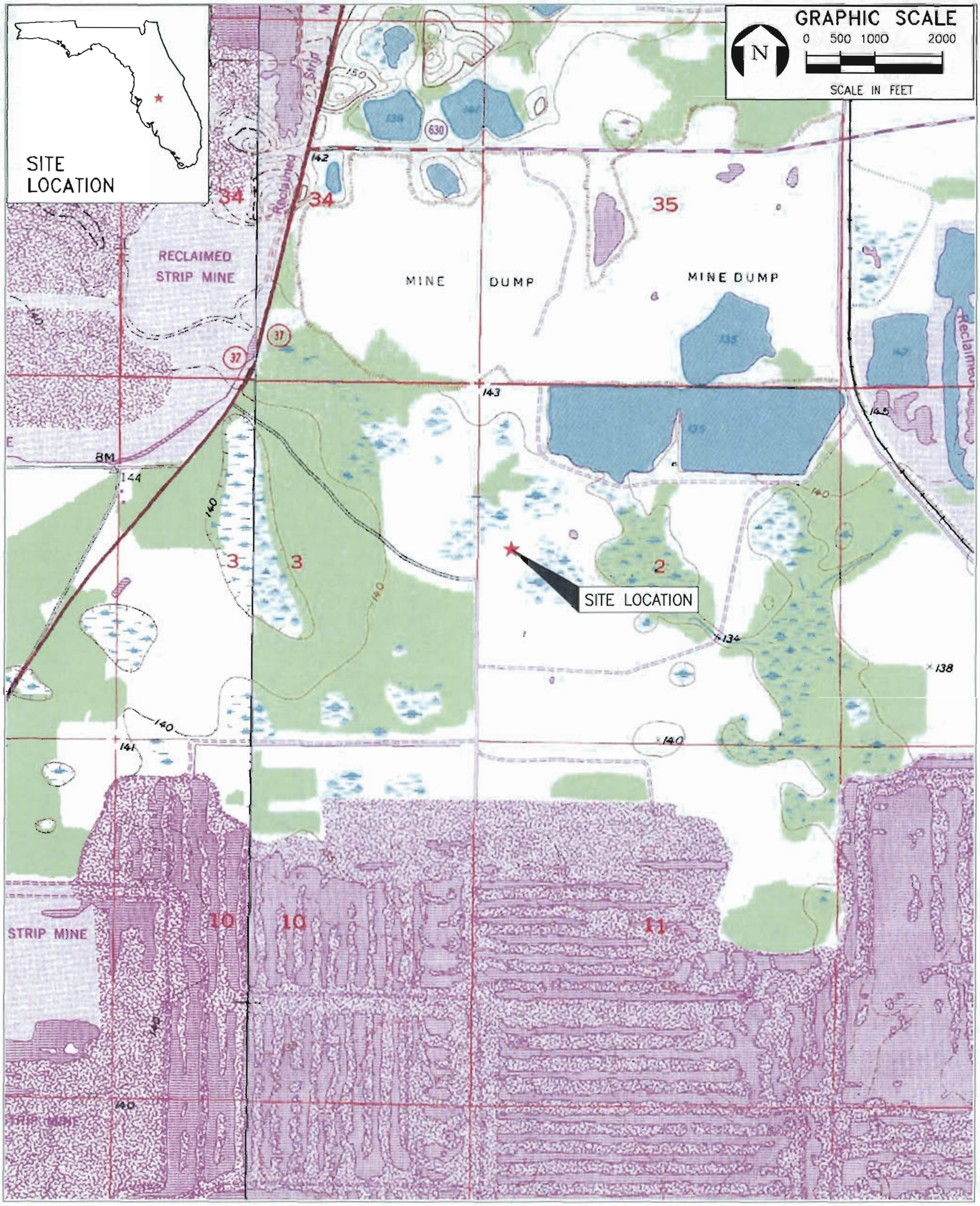

FIGURE 2-1.

AREA MAP

Sources: USGS Quads: Duette NE, FL, 1987; Baird, Fl, 1987; ECT, 2005.

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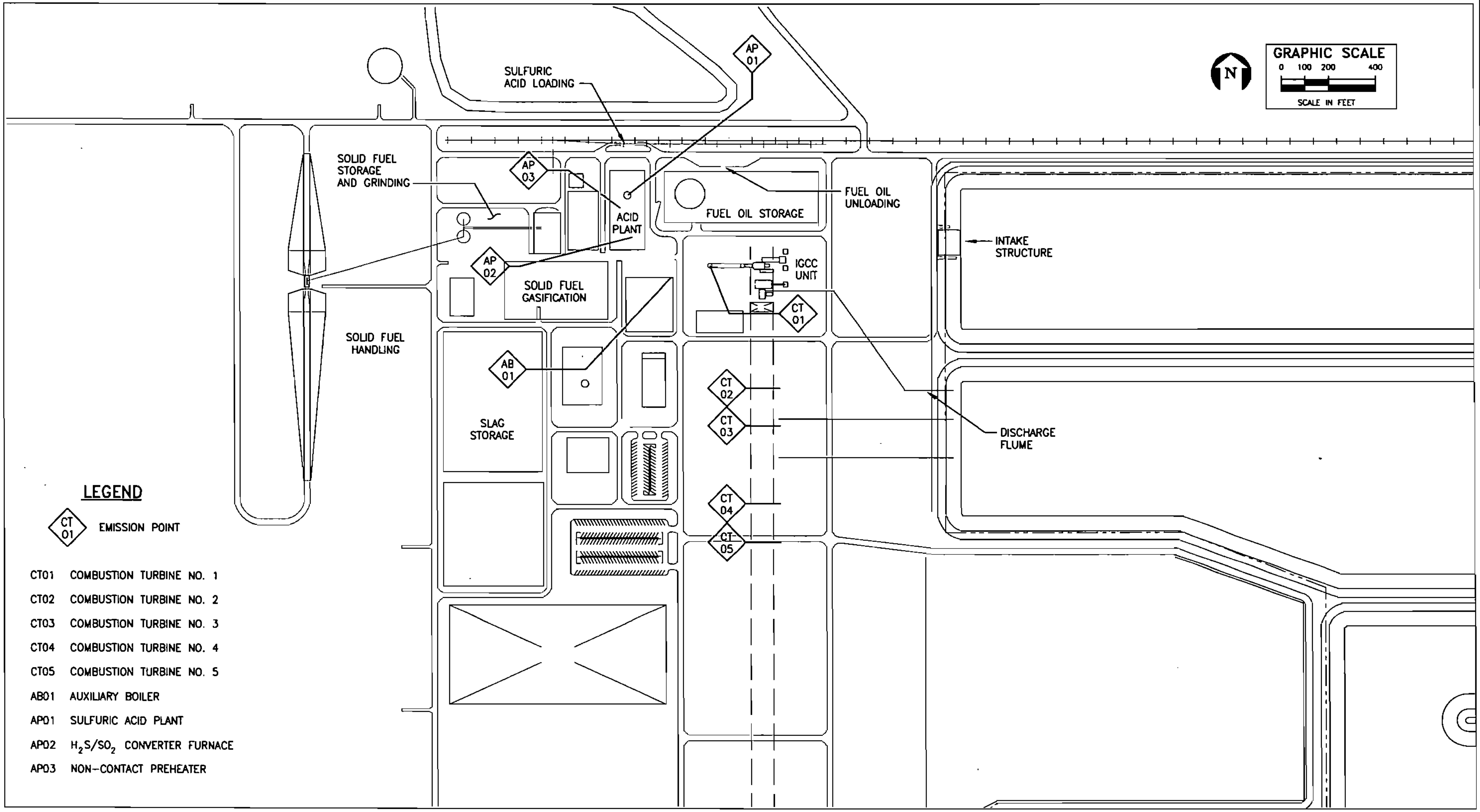

FIGURE 2-2.

POLK POWER STATION PLOT PLAN

Source: Black and Veatch, 2005; ECT, 2005.

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2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

Proposed Units 4 and 5 will consist of two nominal 165-MW simple-cycle CTGs. Figure 2-3 presents a process flow diagram of the two simple-cycle CTGS.

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. 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.

During normal gas-firing operations, CO and NO_x exhaust concentrations are expected to remain essentially constant. However, it is possible that CO and NO_x exhaust concentrations will also remain essentially unchanged at lower loads. For this reason, TEC requests the same permit condition authorizing lower load operations for PPS Units 4 and 5 as specified in Section III, Condition 17.b. of Department Air Permit No. PSD-FL-301A, Project No. 0570040-019-AC issued for H.L. Culbreath Bayside Power Station Units 3A and 3B. As noted previously, the simple-cycle CTGs may operate at annual capacity factors up to 50 and 8.6 percent for natural gas and oil firing, respectively.

Vendor information indicates that Units 4 and 5 will have a heat input of 1,894 and 2,067 million British thermal Units power hour (MMBtu/hr), higher heating value (HHV) at stable baseload and 20°F ambient temperature for natural gas and distillate fuel oil firing, respectively. However, CT vendors typically include a margin in guaranteed heat rates and therefore actual heat inputs could be somewhat higher than provided on the vendor expected performance data sheets. In addition, CTG heat rates will gradually increase over time due to routine CTG operation and degradation. TEC has therefore estimated heat input rates based on a 3.5-percent margin to allow for heat rate degradation

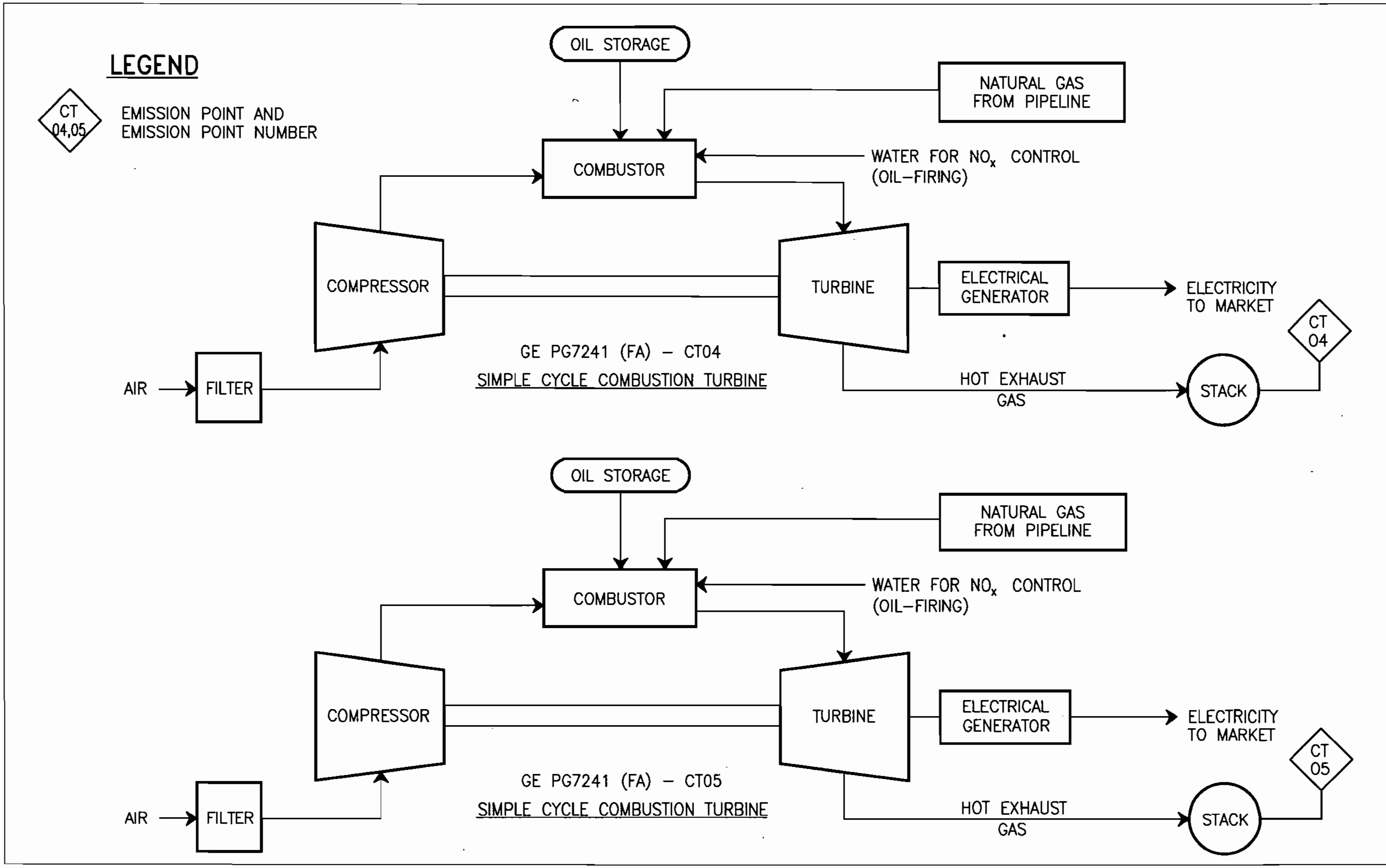

FIGURE 2-3.
SIMPLE CYCLE COMBUSTION TURBINE: PROCESS FLOW DIAGRAM

Source: ECT, 2005.

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over time consistent with the approach taken for the H.L. Culbreath Bayside Power Station CTGs.

The CTGs will utilize DLN 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 and VOC 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 HAP emission 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. HAP emissions 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 degrees Fahrenheit [°F]), baseload, and fuel oil firing. The bases for these emission rates are provided in Appendix C.

Table 2-6 presents projected maximum annualized criteria and HAP 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 750 hr/yr (fuel oil firing) for each CTG, and an ambient temperature of 59°F.

Stack parameters for Units 4 and 5 are provided in Tables 2-7 and 2-8 for natural gas and distillate fuel oil firing, respectively.

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

Steady-State 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	18.0	2.27	10.2	1.28	73.5	9.26	30.3	3.82	3.0	0.38	Neg.	Neg.
	59	18.0	2.27	9.5	1.20	68.8	8.67	28.8	3.63	2.8	0.35	Neg.	Neg.
	90	18.0	2.27	8.8	1.10	63.0	7.94	25.7	3.23	2.6	0.33	Neg.	Neg.
75	20	18.0	2.27	8.2	1.03	58.3	7.35	23.9	3.01	2.1	0.26	Neg.	Neg.
	59	18.0	2.27	7.7	0.97	54.8	6.91	23.0	2.90	1.9	0.24	Neg.	Neg.
	90	18.0	2.27	7.2	0.91	51.3	6.47	21.7	2.74	2.1	0.26	Neg.	Neg.
50	20	18.0	2.27	6.5	0.82	45.5	5.73	19.9	2.50	1.9	0.23	Neg.	Neg.
	59	18.0	2.27	6.2	0.78	43.2	5.44	19.0	2.39	1.7	0.21	Neg.	Neg.
	90	18.0	2.27	5.8	0.73	40.8	5.15	18.4	2.30	1.7	0.21	Neg.	Neg.

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

*Excludes H_2SO_4 mist.

Sources: GE, 1998.
ECT, 2003.

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

Steady-State 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	34.0	4.28	107.8	13.58	338.0	42.59	97.7	12.31	7.6	0.96	0.104	0.013
	59	34.0	4.28	101.5	12.79	319.0	40.19	92.2	11.62	7.2	0.91	0.098	0.012
	90	34.0	4.28	92.3	11.63	290.0	36.54	84.3	10.62	6.5	0.82	0.093	0.012
75	20	34.0	4.28	87.4	11.02	272.0	34.27	78.5	9.89	5.8	0.73	0.084	0.011
	59	34.0	4.28	82.5	10.40	257.0	32.38	74.0	9.32	5.7	0.72	0.079	0.010
	90	34.0	4.28	75.6	9.53	235.0	29.61	67.8	8.55	5.6	0.71	0.073	0.009
50	20	34.0	4.28	68.2	8.59	210.0	26.46	60.7	7.65	5.1	0.64	0.067	0.008
	59	34.0	4.28	64.9	8.18	200.0	25.20	57.9	7.29	4.6	0.58	0.063	0.008
	90	34.0	4.28	59.8	7.54	184.0	23.18	53.2	6.70	4.5	0.57	0.058	0.007

Note: Neg. = negligible

*Excludes H_2SO_4 mist.

Sources: GE, 1998.
ECT, 2005.

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

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4		Distillate Fuel Oil H_2SO_4	
		lb/hr	g/s	lb/hr	g/s
100	20	1.2	0.15	12.4	1.56
	59	1.1	0.13	11.7	1.47
	90	1.0	0.12	10.6	1.34
75	20	0.9	0.12	10.0	1.27
	59	0.9	0.11	9.5	1.19
	90	0.8	0.10	8.7	1.09
50	20	0.7	0.09	7.8	0.99
	59	0.7	0.09	7.5	0.94
	90	0.7	0.08	6.9	0.87

Sources: GE, 1998.
ECT, 2005.

Table 2-4. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Natural Gas

Steady-State Unit Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		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	8.43E-05	1.06E-05	7.84E-03	9.88E-04	1.25E-03	1.58E-04	2.35E-03	2.96E-04	6.27E-03	7.90E-04	4.29E-01	5.40E-02
	59	7.89E-05	9.94E-06	7.34E-03	9.24E-04	1.17E-03	1.48E-04	2.20E-03	2.77E-04	5.87E-03	7.39E-04	4.01E-01	5.05E-02
	90	7.26E-05	9.15E-06	6.75E-03	8.51E-04	1.08E-03	1.36E-04	2.03E-03	2.55E-04	5.40E-03	6.81E-04	3.69E-01	4.65E-02

		Naphthalene		Polycyclic Aromatic Hydrocarbons		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.55E-04	3.21E-05	4.31E-04	5.43E-05	5.68E-03	7.16E-04	2.55E-02	3.21E-03	1.25E-02	1.58E-03
	59	2.38E-04	3.00E-05	4.03E-04	5.08E-05	5.32E-03	6.70E-04	2.38E-02	3.00E-03	1.17E-02	1.48E-03
	90	2.19E-04	2.77E-05	3.71E-04	4.68E-05	4.90E-03	6.17E-04	2.19E-02	2.77E-03	1.08E-02	1.36E-03

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

Source: ECT, 2005.

Table 2-5. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures (per SCCT)—Distillate Fuel Oil

Steady-State Unit Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Arsenic		Benzene		Beryllium		Cadmium		Chromium	
		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	3.42E-02	4.31E-03	2.35E-02	2.96E-03	1.18E-01	1.48E-02	6.63E-04	8.35E-05	1.03E-02	1.29E-03	2.35E-02	2.96E-03
	59	3.22E-02	4.06E-03	2.22E-02	2.79E-03	1.11E-01	1.40E-02	6.25E-04	7.87E-05	9.67E-03	1.22E-03	2.22E-02	2.79E-03
	90	2.93E-02	3.69E-03	2.02E-02	2.54E-03	1.01E-01	1.27E-02	5.68E-04	7.16E-05	8.80E-03	1.11E-03	2.02E-02	2.54E-03

		Formaldehyde		Lead		Manganese		Mercury		Naphthalene		Nickel	
		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	4.94E-01	6.22E-02	2.99E-02	3.77E-03	1.69E-00	2.13E-01	2.57E-03	3.23E-04	7.49E-02	9.43E-03	9.84E-03	1.24E-03
	59	4.65E-01	5.86E-02	2.82E-02	3.55E-03	1.59E-00	2.01E-01	2.42E-03	3.05E-04	7.05E-02	8.89E-03	9.27E-03	1.17E-03
	90	4.23E-01	5.33E-02	2.57E-02	3.23E-03	1.45E-00	1.82E-01	2.20E-03	2.77E-04	6.41E-02	8.08E-03	8.43E-03	1.06E-03

		PAH		Selenium	
		lb/hr	g/s	lb/hr	g/s
100	20	8.55E-02	1.08E-02	5.35E-02	6.74E-03
	59	8.06E-02	1.02E-02	5.04E-02	6.35E-03
	90	7.33E-02	8.24E-03	4.58E-02	5.77E-03

Note: Neg. = negligible

Source: ECT, 2005

Table 2-6. Maximum Annualized Emission Rates for Units 4 and 5

Pollutant	Annualized Emission Rates Units 4 and 5 (tpy)		
	Natural Gas	Distillate Fuel Oil	Total Facility
NO_x	301.5	239.2	540.7
CO	157.6	69.2	226.8
PM/PM_{10}*	78.7	25.6	104.3
SO_2	41.7	76.2	117.9
VOC	12.3	5.4	17.7
H_2SO_4	4.7	8.8	13.5
HAPs			
1,3 Butadiene	3.45E-04	2.42E-02	2.45E-02
Acetaldehyde	3.21E-02		3.21E-02
Acrolein	5.14E-03		5.14E-03
Arsenic		1.66E-02	1.66E-02
Benzene	9.64E-03	8.31E-02	9.28E-02
Beryllium		4.68E-04	4.68E-04
Cadmium		7.25E-03	7.25E-03
Chromium		1.66E-02	1.66E-02
Ethylbenzene	2.57E-02		2.57E-02
Formaldehyde	1.76E-00	3.94E-01	2.11E+00
Lead		2.12E-02	2.12E-02
Manganese		1.19E+00	1.19E+00
Mercury		1.81E-03	1.81E-03
Naphthalene	1.04E-03	5.29E-02	5.39E-02
Nickel		6.95E-03	6.95E-03
PAH	1.77E-03	6.04E-02	6.22E-02
Propylene oxide	2.33E-02		2.33E-02
Selenium		3.78E-02	3.78E-02
Toluene	1.04E-01		1.04E-01
Xylenes	5.14E-02		5.14E-02
Total HAPs	2.01	1.87	3.88

*Excludes H_2SO_4 mist.

Sourcs: TEC, 2005.
GE, 1998.
ECT, 2005.

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

Steady-State 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	114.0	34.7	1,081	856	163.8	49.9	18.0	5.49
	59	114.0	34.7	1,117	876	156.8	47.8	18.0	5.49
	90	114.0	34.7	1,141	889	149.3	45.5	18.0	5.49
75	20	114.0	34.7	1,111	873	133.1	40.6	18.0	5.49
	59	114.0	34.7	1,139	888	129.8	39.6	18.0	5.49
	90	114.0	34.7	1,166	903	125.2	38.2	18.0	5.49
50	20	114.0	34.7	1,160	900	112.7	34.4	18.0	5.49
	59	114.0	34.7	1,184	913	110.6	33.7	18.0	5.49
	90	114.0	34.7	1,200	922	107.2	32.7	18.0	5.49

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

Sources: GE, 1998.
ECT, 2005.

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

Steady-State 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	114.0	34.7	1,067	848	168.0	51.2	18.0	5.49
	59	114.0	34.7	1,098	865	161.7	49.3	18.0	5.49
	90	114.0	34.7	1,130	883	153.1	46.7	18.0	5.49
75	20	114.0	34.7	1,184	913	135.4	41.3	18.0	5.49
	59	114.0	34.7	1,195	919	131.8	40.2	18.0	5.49
	90	114.0	34.7	1,200	922	127.4	38.8	18.0	5.49
50	20	114.0	34.7	1,200	922	113.6	34.6	18.0	5.49
	59	114.0	34.7	1,200	922	112.1	34.2	18.0	5.49
	90	114.0	34.7	1,200	922	109.2	33.3	18.0	5.49

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

Sources: GE, 1998.
ECT, 2005.

3.0 AIR QUALITY STANDARDS AND

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 (Chapter 40, Part 50, Code of Federal Regulations [CFR]). 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 PPS 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 SO_2 and nitrogen dioxide [NO_2]), unclassifiable/attainment (for CO, 1- and 8-hour ozone, and particulate matter less than or equal to 2.5 micrometers [$PM_{2.5}$]), cannot be classified (for total suspended particulates [TSPs]), 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 PPS 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 Units 4 and 5 project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The existing PPS 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 Quality Standards (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2	3-hour[1]		1,300	1,300
	24-hour[1]	365		260
	Annual[2]	80		60
PM_{10}	24-hour[3]	150	150	150
	Annual[4]	50	50	50
$PM_{2.5}$	24-hour[5]	65	65	
	Annual[6]	15	15	
CO	1-hour[1]	40,000		40,000
	8-hour[1]	10,000		10,000
Ozone (ppmv)	1-hour[7]			0.12[9]
	8-hour[8]	0.08	0.08	
NO_2	Annual[2]	100	100	100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

Note: ppmv = part per million by volume.

[1]Not to be exceeded more than once per calendar year.
[2]Arithmetic mean.
[3]The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$, as determined in accordance with 40 CFR 50, Appendix K, is equal to or less than one.
[4]The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix K, is less than or equal to 50 $\mu g/m^3$.
[5]98th percentile concentration, as determined in accordance with 40 CFR 50, Appendix N.
[6]Arithmetic mean concentration, as determined in accordance with 40 CFR 50, Appendix N.
[7]Standard attained when the expected number of calendar 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. The 1-hour ozone standard was revoked on June 15, 2005, one year following the effective date of the 8-hour ozone standard designations.
[8]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.
[9]Applies only in Jacksonville, Miami-Fort Lauderdale-West Palm Beach, and Tampa-St.Petersburg-Clearwater.

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, 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. Appendix C provides detailed emission rate estimates for Units 4 and 5.

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	300-320 ~~540~~.7	40	Yes
CO	126.1 ~~226.8~~	100	Yes
PM	104.3 78.84	25	Yes
PM_{10}	104.3 78.84	15	Yes
SO_2	117.9 41.6	40	Yes
Ozone/VOC	17.7 12.264	40	No
Lead	0.2	0.6	No
Mercury	0.0018	0.1	No
Total fluorides	Neg.	3	No
H_2SO_4 mist	13.5 4.818	7	~~Yes~~ No
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

Note: Neg. = negligible.

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2005.

4,380 hrs/yr

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 Units 4 and 5 in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(38), 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 (NESHAPs), 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 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(3)(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). 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(231), 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.

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(231), F.A.C.

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 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 $PM_{2.5}$, 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.

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.

Table 4-3. PSD Allowable Increments ($\mu g/m^3$)

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 ambient impact analysis for Units 4 and 5 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 Units 4 and 5.

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 (**R**ACT)/**B**ACT/lowest achievable emission rate (**L**AER) **C**learinghouse (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) Air Pollution Control Cost Manual, 6^{th} Edition (EPA, 2002). An assessment of energy, environmental, and economic impacts is then performed. 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.

As indicated in Section 3.3, Table 3-2, projected annual emission rates of NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist for Units 4 and 5 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 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), NESHAPs (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 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.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
<u>Direct Capital Costs</u>	
Instrumentation	0.10 × equipment cost
Sales Tax	0.06 × equipment cost
Freight	0.05 × 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
<u>Indirect Capital Costs</u>	
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
<u>Direct Annual Operating Costs</u>	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Emission Fee Credit	$25 per ton
<u>Indirect Annual Operating Costs</u>	
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, 2002.

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. Units 4 and 5 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.

On February 18, 2005, EPA issued a proposed NSPS Subpart KKKK that will apply to new CTs that commence construction after February 18, 2005. The proposed rule establishes NO_x output-based standards of 1.0 and 1.9 pounds per megawatt-hour (lb/MWhr) of NO_x for CTs greater than 30 MW for gas- and oil-firing, respectively. For SO_2, proposed NSPS Subpart KKKK sets an output-based limit of 0.58 lb/MWhr based on the use of fuels containing no more than 0.05 wt%S. Once NSPS Subpart KKKK is finalized, new CTs constructed after February 18, 2005, will be subject to NSPS Subpart KKKK instead of NSPS Subpart GG. Since Units 4 and 5 will commence construction after February 18, 2005, they will be subject to NSPS Subpart KKKK when finalized.

Purchase contract with GE signed July 21, 2000. TECO Power Services, a subsidiary of TECO Energy.

The proposed Units 4 and 5 have no applicable NESHAP/MACT requirements.

FDEP emission standards for stationary sources are contained in Chapters 62-296, Stationary Sources—Emission Standards, F.A.C. If deemed necessary by FDEP, vapor emission control devices or systems 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 SCCTs. 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 Units 4 and 5. 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 B.

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 oxygen 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 oxygen and on a dry basis; or fuel sulfur content 0.8 wt%S.

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.

BACT emission limitations proposed for Units 4 and 5 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 and distillate fuel oil are due to the oxidation of ash and sulfur contained in these fuels. 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.

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 SCCTs, none of the previously described control equipment have been applied to SCCTs because exhaust gas PM concentrations are inherently low. SCCTs operate with a significant amount of excess air, which generates large exhaust gas flow rates. Units 4 and 5 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 PM/PM_{10} exhaust concentrations for Units 4 and 5 at baseload and 59°F are approximately 0.003 and 0.005 grain per dry standard cubic foot (gr/dscf) while firing natural gas and distillate fuel oil, respectively. 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 SCCTs are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for SCCTs, the use of good combustion practices and clean fuels is considered to be BACT. Units 4 and 5 will use DLN 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. Units 4 and 5 will be fired primarily with pipeline-quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up 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 SCCTs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-4 summarizes PM/PM_{10} BACT emission limits proposed for Units 4 and 5. 10% VE

5.4 BACT ANALYSIS FOR CO

There are two available technologies for controlling CO from SCCTs: 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 SCCTs, approximately 99 percent, CO emissions are inherently low.

Table 5-4. Proposed PM/PM_{10} BACT

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA) (per SCCT unit)	Exclusive use of clean fuels (i.e., natural gas and distillate fuel oil) Efficient combustion design and operation 10.0-percent opacity (indicator of efficient combustion design and operation)

Sources: TEC, 2005.
ECT, 2005.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to carbon dioxide (CO_2) at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. Recently, high temperature oxidation catalysts have been developed which can tolerate higher temperatures (i.e., greater than 1,200°F). Typically, the oxidation catalyst is located within a heat recovery steam generator (HRSG) where temperatures range from 450 to 1,100°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature 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 that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time that 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. For combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO.

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. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. The catalyst will further oxidize sulfur compounds that have been oxidized to SO_2 in the combustion process 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 an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both SCCT combustor design and oxidation catalyst control systems are considered to be technically feasible for Units 4 and 5. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO are provided in the following sections.

5.4.1 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 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 high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from SCCTs fired with natural gas and distillate fuel oil.

Because CO emission rates from SCCTs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements (i.e., below the defined PSD significant impact levels for CO). The location of Units 4 and 5 (rural Polk County) is classified attainment for all criteria pollutants, including CO. As noted in FDEP's 2003 Air Monitoring Report, there have been no exceedances of the CO AAQSs in Florida since 1988. Maximum CO concentrations for all Florida monitoring sites during 2003 were less than 25 percent of the 35-part-per-million (ppm) 1-hour AAQS, and less than 45 percent of the 9-ppm 8-hour AAQS. 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 Units 4 and 5 CO emissions indicated that maximum CO impacts, without oxidation catalyst, will be insignificant. The highest 1- and 8-hour average CO impacts were projected to be only 0.13 and 0.20 percent of the Florida and Federal CO AAQS.

The application of oxidation catalyst technology to a gas turbine will result in an increase in backpressure due to a pressure drop across the catalyst bed. The increased backpressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for Units 4 and 5 is projected to have a pressure drop across the catalyst bed of approximately 1.4 inch of water (H_2O). This pressure drop will result in a 0.28-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 4,740,120 kilowatt-hours (kWh) (16,174 million British thermal units [MMBtu]) per year at baseload (165 MW) operation and 50-percent capacity factor for both SCCTs. This energy penalty is equivalent to the use of 15.4 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 SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kWh, is $42,204 per year for both SCCTs. Actual generation cost based on current fuel prices is $0.150/kWh resulting in an energy penalty of $211,018.

5.4.2 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using OAQPS factors and the project-specific economic factors provided in Table 5-5. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 5-6 and 5-7, respectively.

The base case Units 4 and 5 annual CO emission rate (i.e., for both SCCTs) is 226.8 tpy based on SCCT baseload operation at 59°F for 4,380 hr/yr operation gas-firing and 750 hr/yr oil-firing. The controlled annual CO emission rate, based on 90-percent control efficiency, is 22.7 tpy. The cost effectiveness of oxidation catalyst for CO emissions was
6203
determined to be $6,203 per ton of CO removed using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effective-
8990
ness of $8,990 per ton of CO controlled. Based on these high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. The economic analysis is considered to be conservative (i.e., under-estimate the actual cost effectiveness) since actual SCCT exhaust CO concentrations are expected to

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Table 5-5. Economic Cost Factors

Factor	Units	Value
Interest rate	Percent	7.0*
Control system life	Years	15
Oxidation catalyst life	Years	5
SCR catalyst life	Years	3
Oxidation catalyst control efficiency	Percent	90.0*
SCR catalyst control efficiency (gas)	Percent	67.0
SCR catalyst control efficiency (oil)	Percent	76.0
Electricity cost	$/kWh	0.030*
Electricity cost (current)	$/kWh	0.150
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance	22.00	

* Per FDEP recommendation.

Sources: TEC, 2005.
ECT, 2005.

Table 5-6. Capital Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	3,215,000	A
Sales tax	192,900	0.06 × A
Instrumentation	321,500	0.10 × A
Freight	105,300	0.05 × A
Subtotal Purchased Equipment	**3,890,150**	**B**
Installation		
Foundations and supports	311,212	0.08 × B
Handling and erection	544,621	0.14 × B
Electrical	155,606	0.04 × B
Piping	77,803	0.02 × B
Insulation for ductwork	38,902	0.01 × B
Painting	38,902	0.01 × B
Subtotal Installation Cost	**1,167,045**	
Total Direct Costs (TDC)	**5,057,195**	
Indirect Costs		
Engineering	389,015	0.10 × B
Construction and field expenses	194,508	0.05 × B
Contractor fees	389,015	0.10 × B
Startup	77,803	0.02 × B
Performance test	38,902	0.01 × B
Contingency	116,705	0.03 × B
Total Indirect Costs (TIC)	**1,205,947**	
TOTAL CAPITAL INVESTMENT (TCI)	**6,263,142**	TDC + TIC

Source: ECT, 2005.

Table 5-7. Annual Operating Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	1,889,112	5-year replacement
Credit for Recycled Catalyst	(255,000)	15%
Annualized Catalyst Costs	**398,545**	
Energy Penalties		
Turbine backpressure	142,204	0.28% penalty
Total Direct Costs (TDC)	**540,748**	
Indirect Costs		
Administrative charges	125,263	0.02 × TCI
Property taxes	62,631	0.01 × TCI
Insurance	62,631	0.01 × TCI
Capital recovery	480,245	15 years @ 7.0%
Total Indirect Costs (TIC)	**730,771**	
Permit Fee Credit	(5,104)	$25/ton
TOTAL ANNUAL COST (TAC)	**1,266,415**	TDC + TIC

Sources: ECT, 2005.

be well below the GE guarantees. Results of the oxidation catalyst economic analysis are summarized in Table 5-8.

5.4.3 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from SCCTs is typically required only for facilities located in CO or ozone nonattainment areas.

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 SCCTs fired with natural gas and low sulfur distillate fuel oil. Because CO emission rates from SCCTs are inherently low, further reductions 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 is proposed as BACT for CO. These control techniques have been considered by FDEP to represent BACT for CO for recent SCCT projects

CO exhaust concentrations from Units 4 and 5 will be less than or equal to 9.0 and 20.0 ppmvd for natural gas and distillate fuel oil firing, respectively, at baseload. These CO exhaust concentrations are consistent with recent FDEP CO BACT determinations for SCCT units.

CO BACT emission limits proposed for Units 4 and 5 are provided in Table 5-9. The CO BACT limits shown in Table 5-9 are consistent with the limits recently approved by FDEP for the Bayside Unit 3 SCCTs.

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 SCCT NO_x emissions originate

Table 5-8. 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 Environmenta l Impact
Control Option	lb/hr	tpy	(tpy)	($	($/yr)	($/ton)	(MMBtu/yr)	(Y/N)	(Y/N)
Oxidation catalyst	8.9	22.7	204.1	6,263,142	1,266,415	6,203	16,174	Y	Y
Baseline	88.4	226.8	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 750 hr/yr oil-fired, FDEP economic factors.

Sources: GE, 1998.
ECT, 2005.

Table 5-9. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (per SCCT)		
CO (natural gas)	9.0	36.0
CO (distillate fuel oil)	20.0	92.2

*Corrected to 15-percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

as nitric oxide (NO). NO generated by the SCCT combustion process is subsequently further oxidized in the SCCT 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 DLN 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 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 SCCTs include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

Combustion Process Modifications:

- Water or steam injection, with advanced combustors.
- DLN combustor design.
- XONON™.

Postcombustion Exhaust Gas Treatment Systems:

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

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

Water or Steam Injection

Injection of water or steam into the primary combustion zone of advanced combustors of a CT 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 SCCT 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.

The use of water or steam injection in advanced combustors 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 developed DLN 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 temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical DLN 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 50 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 50 percent of baseline due to flame stability considerations. For SCCTs capable of oil firing, wet injection is employed to control NO_x emissions.

In addition to lean premixed combustion, SCCT DLN combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All SCCTs cool the high-temperature SCCT exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the SCCT turbine. By adding additional dilution air, the hot SCCT 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 SCCT combustion gases are at a higher temperature for a shorter period of time.

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

XONON™

The XONON™ Cool Combustion technology, being developed for CTs by Catalytica Energy Systems, Inc. (CESI), employs a catalyst integral to the CT combustor to reduce the formation of NO_x. In a conventional CT combustor, fuel and air are oxidized in the presence of a flame to produce the hot exhaust gases required for power generation. The XONON™ Cool Combustion technology replaces this conventional combustion process with a two-step approach. First, a portion of the CT fuel is mixed with air and burned in a low-temperature pre-combustor. The main CT fuel is then added and oxidation of the total fuel/air mixture stream is completed by means of flameless, catalytic combustion. The catalyst module is located within the CT combustor. NO_x formation is reduced due to the relatively low oxidation temperatures occurring within the pre-combustor and the flameless combustor catalyst module. Information provided by CESI indicates that the XONON™ Cool Combustion technology is capable of achieving CT NO_x exhaust concentrations of 2.5 ppmvd at 15-percent oxygen.

Commercial operation of the XONON™ Cool Combustion technology is limited to one small (1.5 MW) baseload, natural gas-fired Kawasaki CT operated by the Silicon Valley Power municipal utility. This CT is located in Santa Clara, California. Performance of the XONON™ Cool Combustion technology on larger CTs has not been demonstrated to date.

Availability of the XONON™ Cool Combustion technology is limited to specific gas turbine manufacturers which have agreements with CESI to adapt the proprietary XONON™ combustion system to gas turbines in their product lines. CESI literature indicates that General Electric Power Systems is engaged in development work to adapt the XONON™ Cool Combustion technology to their E- and F-Class CTs. Other CT vendors having agreements with CESI include Pratt & Whitney Canada (for their ST-18 and ST-30 CTs), Rolls Royce Allison, and Solar Turbines.

Proposed Unit 4 and 5 are GE 7FA units. The XONON™ Cool Combustion technology is not yet commercially available for this unit. In addition, XONON™ Cool Combustion technology has not been demonstrated on large, heavy-duty CTs. Accordingly, the XONON™ Cool Combustion technology is not considered to be an available control technology for Units 4 and 5.

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 oxygen) 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:

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

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

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 recently been developed that function at exhaust stream temperatures up to a maximum of approximately 1,050°F. NO_x removal efficiencies for SCR systems typically range from 60 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 CTs has been primarily limited to natural gas-fired units.

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multi-pollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO_x, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ 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 EMx™ oxidation/absorption cycle reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \tag{5}$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \tag{6}$$

$$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \tag{7}$$

CO_2 produced by Reactions (5) and (7) is released to the atmosphere as part of the CT/HRSG exhaust stream.

As shown in Reaction (7), 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 EMx™ regeneration cycle reaction is:

$$KNO_2 + KNO_3 + 4\,H_2 + CO_2 \rightarrow K_2CO_3 + 4\,H_2O_{(g)} + N_2 \tag{8}$$

Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the EMx™ 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, 80 percent of the catalyst sections will be in the oxidation/absorption cycle, while 20 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 8 minutes.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2. The regeneration gas is diluted to under 4 percent hydrogen using steam as a carrier gas; the typical system is designed for 2 percent hydrogen. The regeneration gas reaction is:

$$CH_4 + \frac{1}{2} O_2 + H_2O \rightarrow CO_2 + 3\,H_2 \quad (9)$$

For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the EMx™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

$$CH_4 + 2\,H_2O \rightarrow CO_2 + 4\,H_2 \quad (10)$$

The reformer catalyst is placed upstream of the EMx™ catalyst in a steam reformer reactor. The reformer catalyst is designed for a minimum 50-percent conversion of methane to hydrogen.

A gradual decrease in catalyst temperature is indicative of sulfur masking. EmerChem recommends the installation of a sulfur filter to reduce the rate of catalyst masking. The sulfur filter is placed in the inlet natural gas feed prior to the regeneration production skid. The sulfur filter consists of impregnated granular activated carbon that is housed in a stainless steel vessel. Spent media is discarded as a nonhazardous waste.

The EMx™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. As necessary, an additional catalytic oxidation/absorption system to remove sulfur compounds is installed upstream of the EMx™ catalyst. The sulfur removal catalyst utilizes the same oxidation/absorption cycle and a regeneration cycle as the EMx™ system. During regeneration of the catalyst, either H_2SO_4 mist or SO_2 is released to the atmosphere as part of the CT/HRSG exhaust gas stream. The absorption portion of the process is proprietary. Oxidation/absorption and regeneration reactions are:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \quad (11)$$

$$SO_2 + \frac{1}{2} O_2 \rightarrow SO_3 \quad (12)$$

$$SO_3 + SORBER \rightarrow [SO_3 + SORBER] \quad (13)$$

$$[SO_3 + SORBER] + 4\,H_2 \rightarrow H_2S + 3\,H_2O + [SORBER] \quad (14)$$

(below 500°F)

$$[SO_3 + SORBER] + H_2 \rightarrow SO_2 + H_2O + [SORBER] \quad (15)$$

(above 500°F)

A programmable logic controller (PLC) controls the EMx™ system. The controller is programmed to control all essential EMx™ functions including the opening and closing of louver doors and regeneration gas inlet and outlet valves, and the maintaining of regeneration gas flow to achieve positive pressure in each section during the regeneration cycle.

Utility materials needed for the operation of the EMx™ 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 EMx™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to 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. A high temperature application of SCONO$_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW solar CT located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTs, there are currently no CTs larger than 32 MW that have demonstrated successful application of the EMx™ control technology.

Technical Feasibility

Two of the combustion process modification technologies mentioned (i.e., water or steam injection with advanced combustor design and DLN combustor design) would be feasible for Units 4 and 5. As previously noted, the XONON™ control technology is not currently available for GE 7FA CTs. 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 the Units 4 and 5 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 oxygen) environment. Due to high excess air rates, the oxygen content of the Units 4 and 5 exhausts is approximately 13 percent. The EMx™ 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 Units 4 and 5 exhaust gas streams. In addition, EMx™ control technology has not been commercially demonstrated on a large CT. Units 4 and 5, GE PG7241 (7FA) units, each has a nominal generation capacity of 165 MW. Accordingly, Units 4 and 5 are each 6.6 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 EMx™ technology are unknown. Additional concerns with EMx™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, and the relatively brief operating history of the technology.

For natural gas firing, use of advanced DLN combustor technology will achieve NO_x emission rates comparable to or less than wet injection based on GE SCCT vendor data. Accordingly, the BACT analysis for NO_x for Units 4 and 5 was confined to advanced

DLN combustors (for gas-firing), wet injection (for oil-fi ring), and the application of postcombustion SCR control technology. SCR is considered potentially feasible. However, this technology has primarily been installed on smaller, aeroderivative SCCTs that do not reqire exhaust gas cooling prior to tr eatment. 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 DLN combustor technology will not have a significant adverse impact on SCCT heat rate.

The installation of SCR technology will cause an increase in back pressure on Units 4 and 5 due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqeous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for Units 4 and 5 is projected to have a pressure drop across the catalyst bed of approximately 4.5 inches of water. This pressure drop will result in a 0.9-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 15,236,100 kwh (51,988 MMBtu) per year at baseload (165-MW) operation and 50 percent capacity factor for both SCCTs. This energy penalty is eqivalent to the use of 49.51 million ft^3 of natural gas annually based on a natural gas heating value of 1,050 Btu/ft^3 for both SCCTs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $457,100 per year for both SCCTs. Actual generation cost based on current fuel prices is $0.150/kWh resulting in an energy penalty of $2,285,400.

There are no significant adverse environmental effects due to the use of advanced DLN combustor technology. In contrast, application of 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 slip rate of 5 ppmvd. However, NH_3 slip can increase significantly during start-ups, upsets, or failures of the NH_3 injection system, or due to catalyst

don't inject
During Startup

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.
- 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 DLN combustor/wet injection technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 10.5 and 42.0 ppmvd at 15-percent oxygen for gas and oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 10.0 ppmvd at 15-percent oxygen for gas and oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired aeroderivative SCCTs equipped with SCR controls.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Tables 5-1 and 5-2 and project-specific economic factors previously provided in Table 5-4. Emission reductions were calculated assuming baseload operation for 4,380 and 750 hr/yr for gas- and oil-firing, respectively, at an annual average ambient temperature of 59°F. Tables 5-10 and 5-11 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to Units 4 and 5 was determined to be $10,807 per ton of NO_x removed using the FDEP-recommended economic cost factors. Use of current fuel and electric generation costs results in a cost effectiveness of $15,760 per ton of CO controlled. These control costs are considered economically unreasonable. Table 5-12 summarizes results of the NO_x BACT analysis.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

At baseload operation, maximum NO_x exhaust concentrations from Units 4 and 5 will be 10.5 and 42.0 ppmvd for gas- and oil-firing, respectively, based on the application of DLN combustors (for gas firing) and water injection (for oil firing). NO_x emission rates proposed as BACT for Units 4 and 5 are consistent with prior recent FDEP BACT determinations for SCCTs (e.g., Bayside Unit 3).

Table 5-13 summarizes the NO_x BACT emission limits proposed for Units 4 and 5.

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

Table 5-10. Capital Costs for SCR Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	8,070,000	A
Sales tax	484,200	0.06 × A
Instrumentation	807,000	0.10 × A
Freight	403,500	0.05 × A
Subtotal Purchased Equipment	**9,764,700**	**B**
Installation		
Foundations and supports	781,200	0.08 × B
Handling and erection	1,367,100	0.14 × B
Electrical	390,600	0.04 × B
Piping	195,300	0.02 × B
Insulation for ductwork	97,600	0.01 × B
Painting	97,600	0.01 × B
Subtotal Installation Cost	**2,929,400**	
Total Direct Costs (TDC)	**12,694,100**	
Indirect Costs		
Engineering	976,500	0.10 × B
Construction and field expenses	488,200	0.05 × B
Contractor fees	976,500	0.10 × B
Startup	195,300	0.02 × B
Performance test	97,600	0.01 × B
Contingency	292,900	0.03 × B
Total Indirect Costs (TIC)	**3,027,000**	
TOTAL CAPITAL INVESTMENT (TCI)	**15,721,100**	TDC + TIC

Source: ECT, 2005.

Table 5-11. Annual Operating Costs for Oxidation Catalyst Systems, Units 4 and 5

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Labor and material costs		
Operator	14,100	A
Supervisor	2,100	0.15 × A
Maintenance		
Labor	14,100	B
Materials	2,100	1.0 × B
Subtotal Labor, Material, and Maintenance Costs	**44,400**	**C**
Catalyst costs		
Replacement (materials and labor)	4,294,100	3-year replacement
Annualized Catalyst Costs	**1,636,300**	
Electricity	17,500	
Aqueous Ammonia	53,600	
Energy Penalties		
Turbine backpressure	457,100	0.9% penalty
Total Direct Costs (TDC)	**2,208,900**	
<u>Indirect Costs</u>		
Overhead	26,600	0.60 × C
Administrative charges	314,400	0.02 × TCI
Property taxes	157,200	0.01 × TCI
Insurance	157,200	0.01 × TCI
Capital recovery	1,286,200	15 years @ 7.0%
Permit Fee Credit	(9,600)	$25/ton
Total Indirect Costs (TIC)	**1,932,000**	
TOTAL ANNUAL COST (TAC)	**4,140,900**	TDC + TIC

Sources: ECT, 2005.

Table 5-12. Summary of NO_x BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
	Emission Rates								
Control Option	lb/hr	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)
Oxidation catalyst	60.3	154.7	383.2	15,721,100	4,140,900	10,807	51,988	Y	Y
Baseline	210.8	540.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two GE PG7241 (FA) SCCTs, 100-percent load, 59°F ambient temperature, 4,380 hr/yr gas-fired, 750 hr/yr oil-fired, FDEP economic factors.

Sources: GE, 1998.
ECT, 2005.

Table 5-13. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG 241 (FA) SCCT (Natural Gas firing, Per SCCT)	10.5	68.8
GE PG 241 (FA) SCCT (Distillate Fuel Oil firing, Per SCCT)	42.0	319.0

*Corrected to 15 percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

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.

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 SCCTs because low sulfur fuels are typically used. Units 4 and 5 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, SCCTs 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 SCCT 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 SCCTs 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 SCCT H_2SO_4 mist exhaust concentrations.

Pipeline-quality natural gas contains a negligible amount of sulfur; typically less than 0.50 grains per standard cubic foot (equivalent to 0.0016 weight percent sulfur and 16 parts per million by weight). Ultra-low sulfur diesel fuel (ULSD) containing no more than 0.0015 weight percent sulfur (15 parts per million by weight) will become available at distribution terminals by July 15, 2006 as required by the *Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule* promulgated by EPA on January 18, 2001. Since there are no feasible SO_2 control technologies applicable to Units 4 and 5 other than the use of commercially available low sulfur fuels and because there are no significant differences in the sulfur content of pipeline-quality natural gas, the BACT analysis for SO_2 was confined to the evaluation of the baseline distillate fuel oil containing no more than 0.05 weight percent sulfur (500 parts per million by weight) and ULSD. There are no significant energy and non-air related environmental impacts associated with the use of ULSD. The following sections provide information regarding economic impacts and proposed BACT limits for SO_2.

5.6.2 ECONOMIC IMPACTS

In May 2001, the Energy Information Agency (EIA) of the U.S. Department of Energy (DOE) assessed the additional costs associated with the use of ULSD in a report entitled The Transition to Ultra-Low Sulfur Diesel Fuel: Effects on Prices and Supply. This EIA report estimated an average price increase between current diesel fuel oil containing 500 ppm sulfur and ULSD of 6.8 cents per gallon for the 2007 to 2010 period and 5.4 cents per gallon for the 2011 to 2015 period. For the Units 4 and 5 economic analysis, an average price differential of 5.4 cents was used. Based on 750-hr/yr operation of distillate fuel oil firing per SCCT, annual distillate fuel oil consumption is 20,833,500 gallons per year for both SCCTs. The increase in distillate fuel oil costs in using ULSD, based on the EIA data, is $1,125,009 per year for both SCCTs. The reduction in SO_2 emissions is 73.8 tpy for Units 4 and 5 resulting in a cost effectiveness of $15,231 per ton of SO_2 reduced. Details of the SO_2 economic analysis are provided in Table 5-14.

Table 5-14. SO_2 Economic Analysis for ULSD

Data:

Number of Simple Cycle CTs:	2	
Hourly Fuel Oil Usage:	27,778	gal/hr for two SCCTs (Case 4, 100% load, 59°F)
	203,064	lb/hr for two SCCTs (Case 4, 100% load, 59°F)
Annual Fuel Oil Hours:	750	hr/yr per SCCT
Fuel Oil Cost Premium:	0.054	$/gal (ULSD vs. 0.05 % S)

Calculations:

Annual Fuel Oil Usage:	20,833,500	gal/yr for two SCCTs (Case 4, 100% load, 59°F)
	152,298,000	lb/yr for two SCCTs (Case 4, 100% load, 59°F)
Cost Differential:	1,125,009	$/yr for two SCCTs

Fuel Type	Sulfur (wt%)	SO_2 (ton/yr)	SO_2 ($/ton)
Distillate Fuel Oil (base case)	0.05	76.1	-
Distillate Fuel Oil (ULSD)	0.0015	2.3	15,231

Sources: EIA/DOE, 2001.
GE, 1998.
TEC, 2005.
ECT, 2005.

5.6.3 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 controls are not applicable, use of low sulfur fuel is considered to represent BACT Units 4 and 5. Natural gas utilized for Units 4 and 5 will be pipeline-quality. Distillate fuel oil used for Units 4 and 5 as a back-up fuel source will contain no more than 0.05 wt%S. Table 5-15 summarizes the SO_2 BACT emission limits proposed for Units 4 and 5.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-16 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-17 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-15. Proposed SO_2 BACT Emission Limit

Emission Source	Proposed SO_2 BACT Emission Limits
GE PG 7241 (FA) SCCT (natural gas firing)	Pipeline quality
GE PG 7241 (FA) SCCT (distillate fuel oil firing)	0.05 wt%S

Sources: TEC, 2005.
ECT, 2005.

Table 5-16. Summary of BACT Control Technologies

Pollutant	Control Technology
GE PG7241 (FA) SCCTs	
PM/PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil. • Efficient and complete combustion.
CO	• Efficient and complete combustion.
NO_x	• Use of advanced DLN 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: TEC, 2005.
ECT, 2005.

Table 5-17. Summary of Proposed BACT Emission Limits

Emission Source/Pollutant	Proposed BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (natural gas firing, per SCCT)		
PM/PM_{10}	10-percent opacity	
CO	9.0	36.0
NO_x	10.5	68.8
SO_2/ H_2SO_4	(fuel ≤2.0 gr S/100 scf)	
GE PG7241 (FA) SCCT (distillate fuel firing, per SCCT)		
PM/PM_{10}	10-percent opacity	
CO	20.0	92.2
NO_x	42.0	319.0
SO_2/ H_2SO_4	(fuel ≤0.05 wt % S)	

*Corrected to 15-percent oxygen, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: TEC, 2005.
ECT, 2005.

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, Units 4 and 5 will have the potential to emit 540.7 tpy of NO_x, 226.8 tpy of CO, 104.3 tpy of PM/PM_{10}, 117.9 tpy of SO_2, 17.7 tpy of VOCs, and 13.5 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates for Units 4 and 5. As shown in that table, potential emission increases of all PSD regulated pollutants will be below the applicable PSD significant emission rate levels, with the exception of NO_x, CO, PM, PM_{10}, SO_2, and H_2SO_4 mist. There are no national or Florida AAQS or PSD increments promulgated for H_2SO_4 mist. Accordingly, Units 4 and 5 are subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C. for NO_x, CO, PM, PM_{10}, and SO_2.

6.3 MODEL SELECTION AND USE

For this study, air quality modeling was applied at the refined level. Refined modeling requires more detailed and precise input data than screening modeling, but is presumed to have provided more accurate estimates of source impacts.

The most recent regulatory version of the Industrial Source Complex (ISC3) models (EPA, 2000) 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 02035) 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 PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.4 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.

6.5 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 PPS 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.

6.6 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 PPS (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 Unit 4 and 5 stack bases for modeling purposes).

6.7 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

According to EPA regulations (40 CFR 51), good engineering practice (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 the GEP stack height regulations require that stack heights used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack heights, the actual stack height may be greater. Guidelines for determining GEP stack height have been issued by EPA (1985).

The stack height proposed for Units 4 and 5 (114 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 ISC3 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 (i.e., 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.

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.

6.8 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."

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	 Length (meters)	 Height (meters)
Unit 1 7F HRSG	13.1	40.0	27.4
Gasifier structure	19.2	18.3	91.4
Syngas cooling wings (two)	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 (two) and dryer (one)	—	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 (two)	—	18.0*	60.0
Hot gas cleanup unit	15.8	19.8	85.0
Oil storage tanks (three)	—	30.5	17.4

*Diameter.

Sources: Bechtel, 1994.
Texaco, 1992.
ECT, 2005.

The entire perimeter of the PPS is 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-degree (°) 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 PPS 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.

6.9 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.

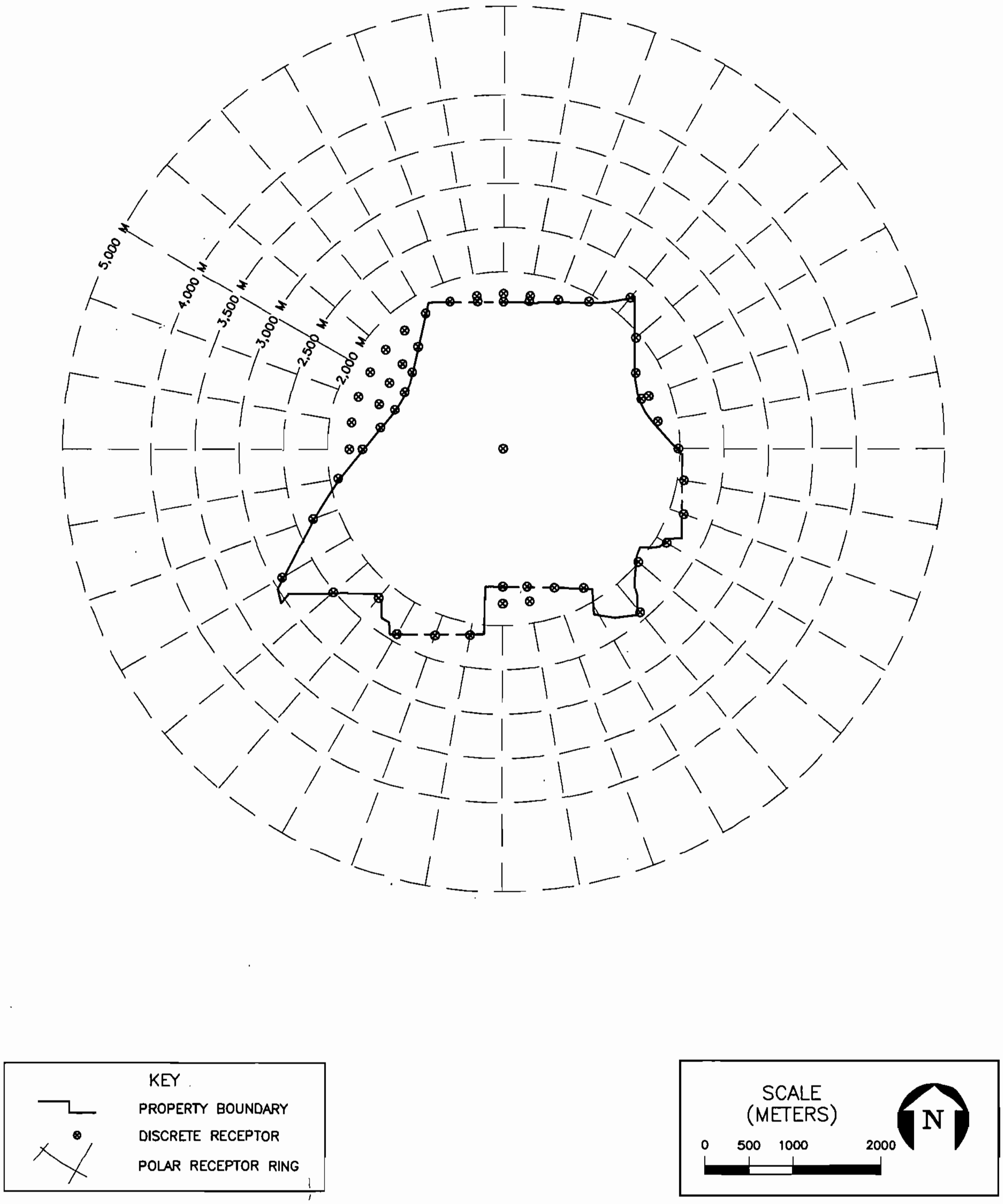

FIGURE 6-1.

LOCATIONS OF DISCRETE RECEPTORS AND CLOSE-IN RECEPTORS

Source: ECT, 2005.

TECO TAMPA ELECTRIC

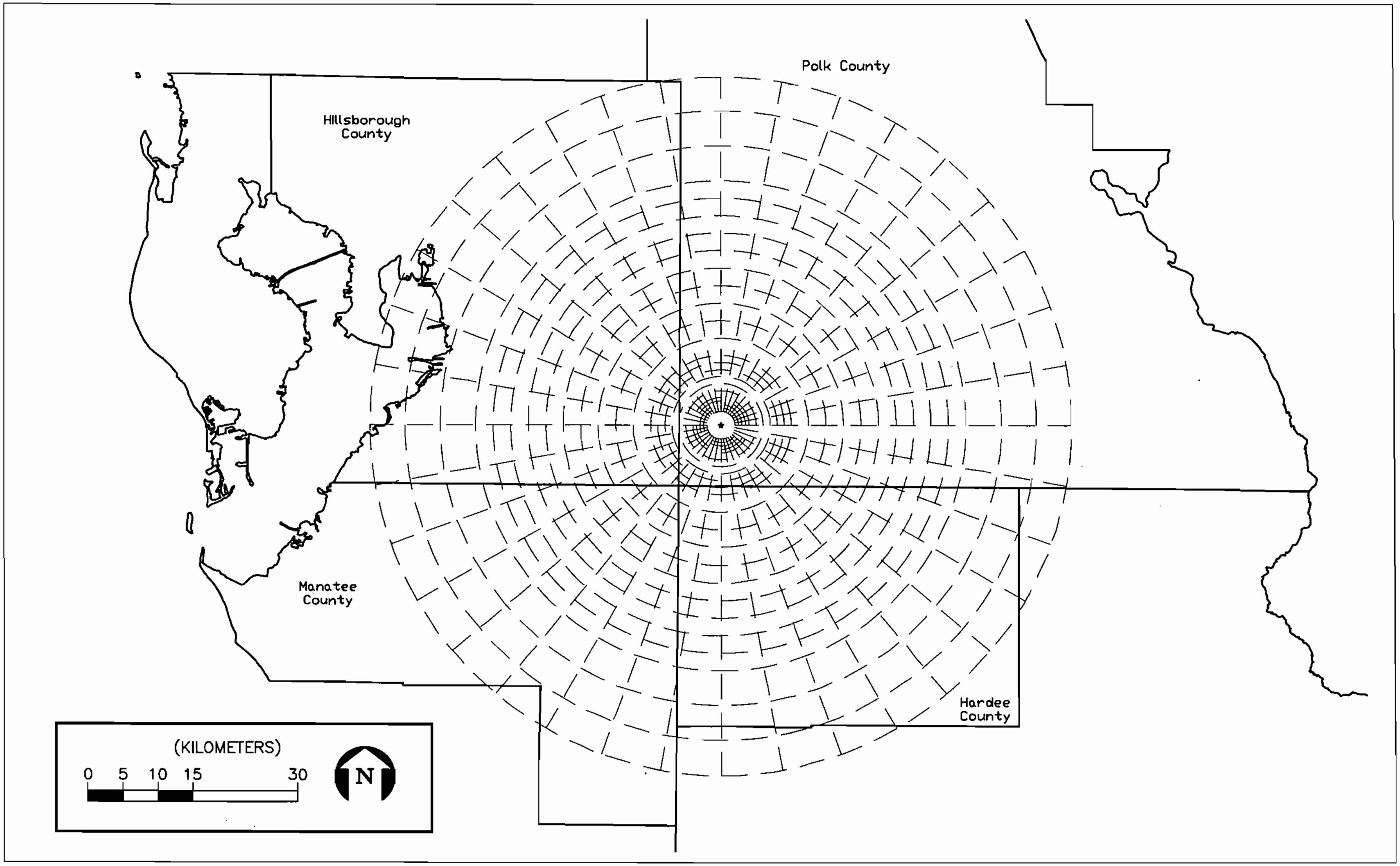

FIGURE 6-2.
POLAR RECEPTOR RINGS

Source: ECT, 2005.

TECO
TAMPA ELECTRIC

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.

6.10 MODELED EMISSION INVENTORY

Modeled on-property emission sources consisted of the two proposed Units 4 and 5. 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 Units 4 and 5 were previously presented in Tables 2-1 through 2-8.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The ISCST3 model was used to model each of the nine Unit 4 and 5 SCCT operating cases for both gas and oil firing. These operating scenarios included three SCCT loads (100, 75, and 50 percent) and three ambient temperatures (20, 59, and 90°F). Modeling was conducted for those project pollutants that exceed the PSD significant emission rate thresholds (i.e., NO_x, SO_2, CO, and PM/PM_{10}).

ISCST3 model results for each year of meteorology evaluated (1992 to 1996) are summarized on Table 7-1 for the Units 4 and 5 gas-firing operating cases. Model results for the oil-firing operating cases are provided on Table 7-2. These tables show the highest project impacts for each year and each operating scenario. For annual average impacts, the air quality analysis conservatively assumed continuous operation for each operating scenario. This approach will significantly over-estimate annual impacts for the full load operating cases since the SCCTs will operate at full load for no more than 4,800 hr/yr per SCCT during gas-firing and for no more than 750 hr/yr per SCCT during oil-firing.

The dispersion model results presented in Tables 7-1 and 7-2 demonstrate that Units 4 and 5 impacts, for all pollutants and averaging periods, will be below the PSD significant impact levels previously shown in Table 3-3. Table 7-3 provides a summary of maximum Units 4 and 5 impacts and the PSD Class II area significant impact levels.

The PPS is located in rural Polk County. With the exception of new power generation facilities, this area has not experienced significant general growth since August 7, 1977. The air quality impacts of any major industrial project in the area of the PPS would have been subject to a detailed regulatory agency assessment under the PSD permitting program.

7.2 CONCLUSIONS

Comprehensive dispersion modeling using the ISCST3 model demonstrates that Units 4 and 5 will result in ambient air quality impacts that are well below the PSD Class II significant impact levels for all pollutants and all averaging periods. Accordingly, a multisource interactive assessment of air quality impacts with respect to the AAQS and PSD Class II increments is not required.

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing

	Case 1 (100% Load, 20°F Ambient)					Case 2 (75% Load, 20°F Ambient)					Case 3 (50% Load, 20°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (Units 4 and 5):															
High, 1-Hour (μg/m³)	2.06	1.86	1.95	1.99	2.06	2.10	2.25	2.37	2.43	2.43	2.82	2.76	2.87	2.67	2.86
High, 3-Hour (μg/m³)	0.96	1.16	1.20	1.28	1.22	1.14	1.38	1.43	1.51	1.45	1.34	1.62	1.68	1.77	1.69
High, 8-Hour (μg/m³)	0.59	0.81	0.59	0.80	0.63	0.70	0.95	0.71	0.95	0.74	0.82	1.10	0.84	1.11	0.86
High, 24-Hour (μg/m³)	0.23	0.23	0.24	0.24	0.25	0.28	0.27	0.29	0.29	0.30	0.32	0.32	0.34	0.33	0.36
Annual (μg/m³)	0.011	0.012	0.013	0.012	0.012	0.015	0.016	0.017	0.015	0.016	0.018	0.021	0.021	0.020	0.019
SO_2															
Emission Rate (g/s)	1.28	1.28	1.28	1.28	1.28	1.03	1.03	1.03	1.03	1.03	0.82	0.82	0.82	0.82	0.82
High, 3-Hour (μg/m³)	0.12	0.15	0.15	0.16	0.16	0.12	0.14	0.15	0.16	0.15	0.11	0.13	0.14	0.15	0.14
High, 24-Hour (μg/m³)	0.030	0.030	0.031	0.031	0.032	0.028	0.028	0.030	0.029	0.031	0.027	0.026	0.028	0.027	0.030
Annual (μg/m³)	0.0015	0.0016	0.0017	0.0016	0.0016	0.0015	0.0017	0.0017	0.0016	0.0016	0.0015	0.0017	0.0017	0.0016	0.0016
NO_2															
Emission Rate (g/s)	9.26	9.26	9.26	9.26	9.26	7.35	7.35	7.35	7.35	7.35	5.73	5.73	5.73	5.73	5.73
Tier 2 Annual (μg/m³)	0.0080	0.0085	0.0090	0.0086	0.0086	0.0080	0.0089	0.0093	0.0085	0.0085	0.0078	0.0088	0.0090	0.0086	0.0083
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour (μg/m³)	0.053	0.052	0.055	0.055	0.057	0.063	0.062	0.066	0.065	0.069	0.074	0.073	0.078	0.076	0.082
Annual (μg/m³)	0.0026	0.0028	0.0029	0.0028	0.0028	0.0033	0.0037	0.0038	0.0035	0.0035	0.0041	0.0047	0.0048	0.0046	0.0044
CO															
Emission Rate (g/s)	3.82	3.82	3.82	3.82	3.82	3.02	3.02	3.02	3.02	3.02	2.50	2.50	2.50	2.50	2.50
High, 1-Hour (μg/m³)	0.79	0.71	0.74	0.76	0.79	0.63	0.68	0.72	0.74	0.73	0.71	0.69	0.72	0.67	0.72
High, 8-Hour (μg/m³)	0.23	0.31	0.23	0.31	0.24	0.21	0.29	0.21	0.29	0.22	0.21	0.27	0.21	0.28	0.22

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing (Page 2 of 3)

	Case 4 (100% Load, 59°F Ambient)					Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour (μg/m³)	2.06	2.04	1.95	1.99	2.07	2.18	2.25	2.43	2.54	2.43	2.82	2.76	2.94	2.68	2.86
High, 3-Hour (μg/m³)	0.99	1.20	1.24	1.31	1.26	1.17	1.41	1.46	1.55	1.48	1.35	1.64	1.70	1.79	1.71
High, 8-Hour (μg/m³)	0.61	0.83	0.61	0.83	0.65	0.72	0.97	0.73	0.97	0.76	0.83	1.11	0.85	1.13	0.87
High, 24-Hour (μg/m³)	0.24	0.24	0.25	0.25	0.26	0.28	0.28	0.30	0.29	0.32	0.33	0.33	0.35	0.34	0.36
Annual (μg/m³)	0.012	0.013	0.014	0.013	0.013	0.015	0.017	0.017	0.016	0.016	0.018	0.021	0.021	0.021	0.020
SO_2															
Emission Rate (g/s)	1.20	1.20	1.20	1.20	1.20	0.97	0.97	0.97	0.97	0.97	0.78	0.78	0.78	0.78	0.78
High, 3-Hour (μg/m³)	0.12	0.14	0.15	0.16	0.15	0.11	0.14	0.14	0.15	0.14	0.11	0.13	0.13	0.14	0.13
High, 24-Hour (μg/m³)	0.029	0.028	0.030	0.030	0.031	0.027	0.027	0.029	0.028	0.031	0.026	0.025	0.027	0.026	0.028
Annual (μg/m³)	0.0014	0.0015	0.0016	0.0015	0.0015	0.0015	0.0016	0.0017	0.0016	0.0016	0.0014	0.0016	0.0017	0.0016	0.0015
NO_2															
Emission Rate (g/s)	8.67	8.67	8.67	8.67	8.67	6.91	6.91	6.91	6.91	6.91	5.44	5.44	5.44	5.44	5.44
Tier 2 Annual (μg/m³)	0.0077	0.0083	0.0088	0.0083	0.0083	0.0079	0.0086	0.0089	0.0083	0.0084	0.0075	0.0085	0.0087	0.0084	0.0080
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour (μg/m³)	0.054	0.054	0.057	0.056	0.059	0.064	0.064	0.067	0.066	0.072	0.075	0.074	0.079	0.077	0.083
Annual (μg/m³)	0.0027	0.0029	0.0031	0.0029	0.0029	0.0034	0.0038	0.0039	0.0037	0.0037	0.0042	0.0047	0.0048	0.0047	0.0044
CO															
Emission Rate (g/s)	3.63	3.63	3.63	3.63	3.63	2.89	2.89	2.89	2.89	2.89	2.40	2.40	2.40	2.40	2.40
High, 1-Hour (μg/m³)	0.75	0.74	0.71	0.72	0.75	0.63	0.65	0.70	0.73	0.70	0.68	0.66	0.71	0.64	0.69
High, 8-Hour (μg/m³)	0.22	0.30	0.22	0.30	0.24	0.21	0.28	0.21	0.28	0.22	0.20	0.27	0.20	0.27	0.21

Table 7-1. Air Quality Impact Analysis Summary, Units 4 and 5—Natural Gas Firing (Page 3 of 3)

	Case 7 (100% Load, 90°F Ambient)					Case 8 (80% Load, 90°F Ambient)					Case 9 (50% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour (μg/m³)	2.07	2.16	2.20	2.16	2.08	2.26	2.33	2.52	2.66	2.44	2.91	2.76	2.94	2.68	2.94
High, 3-Hour (μg/m³)	1.03	1.25	1.29	1.37	1.31	1.20	1.46	1.51	1.60	1.53	1.38	1.68	1.74	1.84	1.75
High, 8-Hour (μg/m³)	0.63	0.86	0.64	0.86	0.68	0.74	1.00	0.75	1.00	0.78	0.85	1.13	0.87	1.15	0.89
High, 24-Hour (μg/m³)	0.25	0.25	0.26	0.26	0.27	0.29	0.29	0.31	0.30	0.32	0.34	0.33	0.36	0.35	0.37
Annual (μg/m³)	0.013	0.014	0.015	0.014	0.013	0.016	0.017	0.018	0.017	0.017	0.019	0.021	0.022	0.021	0.020
SO_2															
Emission Rate (g/s)	1.10	1.10	1.10	1.10	1.10	0.91	0.91	0.91	0.91	0.91	0.73	0.73	0.73	0.73	0.73
High, 3-Hour (μg/m³)	0.11	0.14	0.14	0.15	0.14	0.11	0.13	0.14	0.15	0.14	0.10	0.12	0.13	0.13	0.13
High, 24-Hour (μg/m³)	0.027	0.027	0.029	0.028	0.030	0.027	0.026	0.028	0.027	0.030	0.025	0.024	0.026	0.025	0.027
Annual (μg/m³)	0.0014	0.0015	0.0016	0.0015	0.0015	0.0014	0.0016	0.0016	0.0015	0.0015	0.0014	0.0016	0.0016	0.0016	0.0015
NO_2															
Emission Rate (g/s)	7.94	7.94	7.94	7.94	7.94	6.47	6.47	6.47	6.47	6.47	5.15	5.15	5.15	5.15	5.15
Tier 2 Annual (μg/m³)	0.0075	0.0082	0.0087	0.0080	0.0079	0.0076	0.0084	0.0087	0.0082	0.0082	0.0074	0.0083	0.0085	0.0083	0.0078
PM_{10}															
Emission Rate (g/s)	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27	2.27
High, 24-Hour (μg/m³)	0.057	0.056	0.059	0.059	0.062	0.066	0.066	0.070	0.068	0.074	0.076	0.076	0.081	0.079	0.085
Annual (μg/m³)	0.0029	0.0031	0.0033	0.0031	0.0030	0.0036	0.0039	0.0041	0.0038	0.0038	0.0043	0.0049	0.0050	0.0049	0.0046
CO															
Emission Rate (g/s)	3.24	3.24	3.24	3.24	3.24	2.74	2.74	2.74	2.74	2.74	2.31	2.31	2.31	2.31	2.31
High, 1-Hour (μg/m³)	0.67	0.70	0.71	0.70	0.67	0.62	0.64	0.69	0.73	0.67	0.67	0.64	0.68	0.62	0.68
High, 8-Hour (μg/m³)	0.20	0.28	0.21	0.28	0.22	0.20	0.27	0.21	0.27	0.21	0.20	0.26	0.20	0.27	0.21

Maximum Impacts	Project Impact	Case No.	Year	Class II SIL	% of SIL (%)
SO_2					
High, 3-Hour (μg/m³)	0.16	1	1995	25	0.66
High, 24-Hour (μg/m³)	0.032	1	1996	5	0.65
Annual (μg/m³)	0.0016	2	1994	1	0.16
NO_2					
Annual (μg/m³)	0.0093	2	1994	1	0.93
PM_{10}					
High, 24-Hour (μg/m³)	0.08	9	1996	5	1.69
Annual (μg/m³)	0.0050	9	1994	1	0.50
CO					
High, 1-Hour (μg/m³)	0.79	1	1996	2,000	0.039
High, 8-Hour (μg/m³)	0.31	1	1993	500	0.06

Source: ECT, 2005.

Table 7-2 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing

	Case 1 (100% Load, 20°F Ambient)					Case 2 (75% Load, 20°F Ambient)					Case 3 (50% Load, 20°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (Units 4 and 5):															
High, 1-Hour ($\mu g/m^3$)	2.06	1.86	1.95	1.99	2.06	2.10	2.25	2.37	2.43	2.43	2.82	2.76	2.87	2.67	2.86
High, 3-Hour ($\mu g/m^3$)	0.96	1.16	1.20	1.28	1.22	1.14	1.38	1.43	1.51	1.45	1.34	1.62	1.68	1.77	1.69
High, 8-Hour ($\mu g/m^3$)	0.59	0.81	0.59	0.80	0.63	0.70	0.95	0.71	0.95	0.74	0.82	1.10	0.84	1.11	0.86
High, 24-Hour ($\mu g/m^3$)	0.23	0.23	0.24	0.24	0.25	0.28	0.27	0.29	0.29	0.30	0.32	0.32	0.34	0.33	0.36
Annual ($\mu g/m^3$)	0.011	0.012	0.013	0.012	0.012	0.015	0.016	0.017	0.015	0.016	0.018	0.021	0.021	0.020	0.019
SO_2															
Emission Rate (g/s)	13.58	13.58	13.58	13.58	13.58	11.02	11.02	11.02	11.02	11.02	8.59	8.59	8.59	8.59	8.59
High, 3-Hour ($\mu g/m^3$)	1.30	1.58	1.63	**1.74**	1.66	1.26	1.52	1.58	1.67	1.60	1.15	1.40	1.44	1.52	1.45
High, 24-Hour ($\mu g/m^3$)	0.316	0.313	0.329	0.328	**0.343**	0.305	0.302	0.319	0.314	0.336	0.279	0.277	0.295	0.287	0.309
Annual ($\mu g/m^3$)	0.0156	0.0167	0.0176	0.0168	0.0168	0.0161	0.0178	**0.0185**	0.0171	0.0171	0.0155	0.0177	0.0180	0.0172	0.0166
NO_2															
Emission Rate (g/s)	42.59	42.59	42.59	42.59	42.59	34.27	34.27	34.27	34.27	34.27	26.46	26.46	26.46	26.46	26.46
Tier 2 Annual ($\mu g/m^3$)	0.0366	0.0393	0.0413	0.0395	0.0395	0.0375	0.0415	**0.0432**	0.0398	0.0399	0.0358	0.0409	0.0416	0.0398	0.0384
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour ($\mu g/m^3$)	0.100	0.099	0.104	0.103	0.108	0.118	0.117	0.124	0.122	0.130	0.139	0.138	0.147	0.143	0.154
Annual ($\mu g/m^3$)	0.0049	0.0053	0.0055	0.0053	0.0053	0.0062	0.0069	0.0072	0.0066	0.0066	0.0077	0.0088	0.0090	0.0086	0.0083
CO															
Emission Rate (g/s)	12.31	12.31	12.31	12.31	12.31	9.89	9.89	9.89	9.89	9.89	7.65	7.65	7.65	7.65	7.65
High, 1-Hour ($\mu g/m^3$)	2.53	2.29	2.40	2.44	**2.54**	2.08	2.23	2.35	2.41	2.40	2.16	2.11	2.20	2.05	2.19
High, 8-Hour ($\mu g/m^3$)	0.73	**0.99**	0.73	0.99	0.78	0.69	0.94	0.70	0.94	0.73	0.63	0.84	0.64	0.85	0.66

Table 7-2 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing (Page 2 of 3)

	Case 4 (100% Load, 59°F Ambient)					Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour ($\mu g/m^3$)	2.06	2.04	1.95	1.99	2.07	2.18	2.25	2.43	2.54	2.43	2.82	2.76	2.94	2.68	2.86
High, 3-Hour ($\mu g/m^3$)	0.99	1.20	1.24	1.31	1.26	1.17	1.41	1.46	1.55	1.48	1.35	1.64	1.70	1.79	1.71
High, 8-Hour ($\mu g/m^3$)	0.61	0.83	0.61	0.83	0.65	0.72	0.97	0.73	0.97	0.76	0.83	1.11	0.85	1.13	0.87
High, 24-Hour ($\mu g/m^3$)	0.24	0.24	0.25	0.25	0.26	0.28	0.28	0.30	0.29	0.32	0.33	0.33	0.35	0.34	0.36
Annual ($\mu g/m^3$)	0.012	0.013	0.014	0.013	0.013	0.015	0.017	0.017	0.016	0.016	0.018	0.021	0.021	0.021	0.020
SO_2															
Emission Rate (g/s)	12.79	12.79	12.79	12.79	12.79	10.40	10.40	10.40	10.40	10.40	8.18	8.18	8.18	8.18	8.18
High, 3-Hour ($\mu g/m^3$)	1.26	1.53	1.58	1.68	1.61	1.21	1.47	1.52	1.61	1.54	1.10	1.34	1.39	1.47	1.40
High, 24-Hour ($\mu g/m^3$)	0.306	0.303	0.318	0.317	0.332	0.294	0.292	0.309	0.303	0.328	0.269	0.267	0.284	0.276	0.298
Annual ($\mu g/m^3$)	0.0151	0.0164	0.0174	0.0164	0.0163	0.0158	0.0172	0.0179	0.0167	0.0168	0.0150	0.0171	0.0173	0.0169	0.0160
NO_2															
Emission Rate (g/s)	40.19	40.19	40.19	40.19	40.19	32.38	32.38	32.38	32.38	32.38	25.20	25.20	25.20	25.20	25.20
Tier 2 Annual ($\mu g/m^3$)	0.0357	0.0386	0.0409	0.0386	0.0384	0.0369	0.0402	0.0418	0.0391	0.0391	0.0347	0.0394	0.0401	0.0389	0.0370
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour ($\mu g/m^3$)	0.102	0.101	0.107	0.106	0.111	0.121	0.120	0.127	0.125	0.135	0.140	0.139	0.149	0.145	0.156
Annual ($\mu g/m^3$)	0.0051	0.0055	0.0058	0.0055	0.0054	0.0065	0.0071	0.0074	0.0069	0.0069	0.0079	0.0089	0.0091	0.0088	0.0084
CO															
Emission Rate (g/s)	11.62	11.62	11.62	11.62	11.62	9.32	9.32	9.32	9.32	9.32	7.29	7.29	7.29	7.29	7.29
High, 1-Hour ($\mu g/m^3$)	2.40	2.37	2.26	2.31	2.41	2.03	2.10	2.27	2.37	2.27	2.06	2.01	2.14	1.95	2.09
High, 8-Hour ($\mu g/m^3$)	0.70	0.96	0.71	0.96	0.75	0.67	0.90	0.68	0.91	0.71	0.61	0.81	0.62	0.82	0.64

Table 7-3 Air Quality Impact Analysis Summary, Units 4 and 5—Distillate Fuel Oil Firing (Page 3 of 3)

	Case 7 (100% Load, 90°F Ambient)					Case 8 (80% Load, 90°F Ambient)					Case 9 (50% Load, 90°F Ambient)				
	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996	1992	1993	1994	1995	1996
Nominal 10 g/s Impacts (10 SCCTs):															
High, 1-Hour ($\mu g/m^3$)	2.07	2.16	2.20	2.16	2.08	2.26	2.33	2.52	2.66	2.44	2.91	2.76	**2.94**	2.68	2.94
High, 3-Hour ($\mu g/m^3$)	1.03	1.25	1.29	1.37	1.31	1.20	1.46	1.51	1.60	1.53	1.38	1.68	1.74	**1.84**	1.75
High, 8-Hour ($\mu g/m^3$)	0.63	0.86	0.64	0.86	0.68	0.74	1.00	0.75	1.00	0.78	0.85	1.13	0.87	**1.15**	0.89
High, 24-Hour ($\mu g/m^3$)	0.25	0.25	0.26	0.26	0.27	0.29	0.29	0.31	0.30	0.32	0.34	0.33	0.36	0.35	0.37
Annual ($\mu g/m^3$)	0.013	0.014	0.015	0.014	0.013	0.016	0.017	0.018	0.017	0.017	0.019	0.021	**0.022**	0.021	0.020
SO_2															
Emission Rate (g/s)	11.63	11.63	11.63	11.63	11.63	9.53	9.53	9.53	9.53	9.53	7.54	7.54	7.54	7.54	7.54
High, 3-Hour ($\mu g/m^3$)	1.20	1.45	1.50	1.59	1.52	1.15	1.39	1.44	1.52	1.46	1.04	1.27	1.31	1.38	1.32
High, 24-Hour ($\mu g/m^3$)	0.290	0.288	0.303	0.300	0.315	0.278	0.276	0.293	0.287	0.310	0.254	0.252	0.269	0.261	0.281
Annual ($\mu g/m^3$)	0.0147	0.0160	0.0170	0.0157	0.0155	0.0150	0.0165	0.0171	0.0161	0.0160	0.0144	0.0162	0.0165	0.0161	0.0153
NO_2															
Emission Rate (g/s)	36.54	36.54	36.54	36.54	36.54	29.61	29.61	29.61	29.61	29.61	23.18	23.18	23.18	23.18	23.18
Tier 2 Annual ($\mu g/m^3$)	0.0346	0.0377	0.0401	0.0370	0.0365	0.0350	0.0386	0.0399	0.0374	0.0373	0.0333	0.0374	0.0381	0.0372	0.0353
PM_{10}															
Emission Rate (g/s)	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28
High, 24-Hour ($\mu g/m^3$)	0.107	0.106	0.111	0.111	0.116	0.125	0.124	0.131	0.129	0.139	0.144	0.143	0.153	0.148	**0.160**
Annual ($\mu g/m^3$)	0.0054	0.0059	0.0063	0.0058	0.0057	0.0067	0.0074	0.0077	0.0072	0.0072	0.0082	0.0092	**0.0094**	0.0092	0.0087
CO															
Emission Rate (g/s)	10.62	10.62	10.62	10.62	10.62	8.55	8.55	8.55	8.55	8.55	6.70	6.70	6.70	6.70	6.70
High, 1-Hour ($\mu g/m^3$)	2.20	2.29	2.34	2.30	2.21	1.93	2.00	2.15	2.28	2.08	1.95	1.85	1.97	1.80	1.97
High, 8-Hour ($\mu g/m^3$)	0.67	0.92	0.68	0.91	0.72	0.63	0.85	0.64	0.86	0.67	0.57	0.76	0.58	0.77	0.60

Maximum Impacts	Project Impact	Case No.	Year	Class II SIL	% of SIL (%)
SO_2					
High, 3-Hour ($\mu g/m^3$)	1.74	1	1995	25	6.95
High, 24-Hour ($\mu g/m^3$)	0.343	1	1996	5	6.87
Annual ($\mu g/m^3$)	0.0161	2	1994	1	1.61
NO_2					
Annual ($\mu g/m^3$)	0.0432	2	1994	1	4.32
PM_{10}					
High, 24-Hour ($\mu g/m^3$)	0.16	9	1996	5	3.19
Annual ($\mu g/m^3$)	0.0094	9	1994	1	0.94
CO					
High, 1-Hour ($\mu g/m^3$)	2.54	2	1995	2,000	0.13
High, 8-Hour ($\mu g/m^3$)	0.99	2	1995	500	0.20

Source: ECT, 2005.

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Table 7-3. 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	0.043	1
PM_{10}	Annual	0.0094	1
	24-hour	0.16	5
SO_2	Annual	0.016	1
	24-hour	0.34	5
	3-hour	1.7	25
CO	8-Hour	0.99	500
	1-Hour	2.5	2,000

Source: ECT, 2005.

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 Mulberry, Polk County, approximately 15 km north of the PPS. The FDEP monitoring station at Mulberry monitors PM_{10} and SO_2. The nearest FDEP station that monitors ozone is located in Lakeland, Polk County, approximately 25 km north of the project site. The nearest FDEP station that monitors NO_x is located in Tampa, Hillsborough County, approximately 50 km northwest of the project site. The nearest FDEP station that monitors CO is located in Tampa, Hillsborough County, approximately 35 km northwest of the project site. The nearest FDEP station monitoring for lead is situated in Tampa, Hillsborough County, approximately 50 km northwest of the project site. Summaries of 2003 and 2004 ambient air quality data for these FDEP stations are 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 Units 4 and 5 in excess of their respective significant emission rates, preconstruction monitoring is required. However, 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 Units 4 and 5. The results of these analyses were 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 0.16 microgram per cubic meter ($\mu g/m^3$). This concentration is below the 10-$\mu g/m^3$ *de minimis* level ambient impact level.

Table 8-1. Summary of FDEP 2003 Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site Name	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Plant Origin (km)	Direction From Plant Origin (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	15	349	24-Hr	Jan-Dec	346	51	42		150[1]
									Annual					20	50[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	19	9	24-Hr	Jan-Dec	355	59	49		150[1]
									Annual					20	50[2]
	Hillsborough	Tampa	Gardinier Park	0570083	363,890.0	3,082,701.0	42	292	24-Hr	Jan-Dec	322	59	58		150[1]
									Annual					25	50[2]
	Hillsborough	Tampa	Eisenhower Jr. High School	0570085	365,199.0	3,074,807.0	38	282	24-Hr	Jan-Dec	58	41	37		150[1]
									Annual					20	50[2]
SO_2	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	15	349	1-Hr	Jan-Dec	8,282	431.0	193.3		
									3-Hr			117.6	88.8		1,300[3]
									24-Hr			44.4	39.2		365[3]
									Annual					13.1	80[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	19	9	1-Hr	Jan-Dec	3,965	326.5	206.4		
									3-Hr			117.6	81.0		1,300[3]
									24-Hr			26.1	23.5		365[3]
									Annual					10.4	80[2]
NO_2	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	47	273	1-Hr	Jan-Dec	8,444	90.1	90.1		100[2]
									Annual					13.1	
	Hillsborough	Tampa	5121 Gandy Blvd	0571065	348,560.0	3,086,060.0	57	289	1-Hr	Jan-Dec	8,636	108.9	107.0		100[2]
									Annual					18.8	
CO	Hillsborough	Tampa	4702 Central Avenue	0571070	357,000.0	3,096,500.0	54	303	1-Hr	Jan-Dec	8,459	8,342.9	6,514.3		40,000[3]
									8-Hr			4,114.3	3,771.4		10,000[3]
	Hillsborough	Plant City	One Raider Place	0574004	389,300.0	3,096,710.0	33	336	1-Hr	Jan-Dec	8,696	2,742.9	2,514.3		40,000[3]
									8-Hr			1,257.1	1,257.1		10,000[3]
O_3	Polk	Lakeland	2727 Shepherd Road	1056005	401,588.0	3,090,755.0	24	358	1-Hr	Mar-Oct	239	176.3			235[4]
	Polk	Lakeland	Sikes Elementary	1056006	404,435.0	3,100,652.0	34	3	1-Hr	Mar-Oct	245	176.3			235[4]
	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	47	273	1-Hr	Mar-Oct	239	219.4			235[4]
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	47	304	24-Hr		59	3.2			
										Jan-Mar		0.74			1.5[2]
										Apr-Jun		0.12			1.5[2]
										Jul-Sep		0.41			1.5[2]
										Oct-Dec		0.55			1.5[2]

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Indicates that the mean does not sastify summary criteria

Sources: ECT, 2005.
FDEP, 2005.

Table 8-2. Summary of FDEP 2004 Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site Name	Site No.	Site UTM Coordinates: Easting	Site UTM Coordinates: Northing	Distance From Plant Origin (km)	Direction From Plant Origin (Vector °)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Polk	Mulberry	SR640 & Anderson Road	1050010	399,800.0	3,081,600.0	25	347	24-Hr	Jan-Dec	349	66	51		150[1]
									Annual					20.6	50[2]
	Polk	Mulberry	Mulberry High School	1052006	405,500.0	3,086,000.0	29	0	24-Hr	Jan-Dec	347	68	50		150[1]
									Annual					20.8	50[2]
	Hillsborough	Tampa	Gardinier Park	0570083	363,890.0	3,082,701.0	49	301	24-Hr	Jan-Dec	364	78	61		150[1]
									Annual					26.9	50[2]
	Hillsborough	Tampa	Eisenhower Jr. High School	0570085	365,199.0	3,074,807.0	44	293	24-Hr	Jan-Dec	60	38	30		150[1]
									Annual					19.1	50[2]
SO_2	Polk	Mulberry	Anderson Avenue	1050010	405,500.0	3,086,000.0	29	0	1-Hr	Jan-Dec	8,514	251.5	235.8		
									3-Hr			112.7	104.8		1,300[3]
									24-Hr			41.9	36.7		365[3]
									Annual					10.5	80[2]
NO_2	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	51	283	1-Hr	Jan-Dec	8,171	73.4	71.5		100[2]
									Annual					10.5	
	Hillsborough	Tampa	5121 Gandy Blvd	0571065	348,560.0	3,086,060.0	64	297	1-Hr	Jan-Dec	8,182	92.2	90.3		100[2]
									Annual					17.3	
CO	Hillsborough	Tampa	4702 Central Avenue	0571070	357,000.0	3,096,500.0	62	309	1-Hr	Jan-Dec	8,656	5,175.0	5,060.0		40,000[3]
									8-Hr			3,335.0	2,875.0		10,000[3]
	Hillsborough	Plant City	One Raider Place	0574004	389,300.0	3,096,710.0	42	338	1-Hr	Jan-Dec	8,716	2,242.5	2,070.0		40,000[3]
									8-Hr			1,495.0	1,495.0		10,000[3]
O_3	Polk	Lakeland	2727 Shepherd Road	1056005	401,588.0	3,090,755.0	34	354	1-Hr	Mar-Oct	242	164.9			235[4]
									8-Hr	Mar-Oct	97	143.3			
	Polk	Lakeland	Sikes Elementary	1056006	401,588.0	3,090,755.0	34	354	1-Hr	Mar-Oct	235	176.7			235[4]
									8-Hr	Mar-Oct	95	151.2			
	Hillsborough	Tampa	Simmons Park	0570081	355,544.0	3,069,100.0	51	283	1-Hr	Mar-Oct	233	196.3			235[4]
									8-Hr	Mar-Oct	94	164.9			
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	55	311	24-Hr		61	3.5			
										Jan-Mar		1.26			1.5[2]
										Apr-Jun		0.39			1.5[2]
										Jul-Sep		0.46			1.5[2]
										Oct-Dec		0.59			1.5[2]

[1] 99th percentile
[2] Arithmetic mean
[3] 2nd high
[4] 4th highest day with hourly value exceeding standard over a 3-year period
[5] Indicates that the mean does not sastify summary criteria

Sources: ECT, 2005.
FDEP, 2005.

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Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.2.2 SO_2

The maximum 24-hour SO_2 impact was predicted to be 0.34 $\mu g/m^3$. This concentration is below the 13-$\mu g/m^3$ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO_2 is appropriate in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.043 $\mu g/m^3$. This concentration is below the 14-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

8.2.4 CO

The maximum 8-hour CO impact was predicted to be 0.99 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO 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 Units 4 and 5 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 SCCTs are being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, the SCCTs are projected to generate approximately five 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 SCCTs 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 PPS due to operation of the proposed Units 4 and 5 will be well below applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the PPS are anticipated. The following sections discuss potential impacts on the nearest Class I area; the Chassahowitzka NWR.

9.2.1 IMPACTS ON SOILS

The U.S. Department of Agriculture (USDA) (1991a and 1991b) lists the primary soil type in Chassahowitzka NWR 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 the Unit 4 and 5 project, given the relatively 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 fresh water 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 salt water 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 the PPS due to operation of Units 4 and 5 would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka NWR due to emissions from PPS Units 4 and 5 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 NWR relative to the immediate PPS plant vicinity and the absence of any plant species at Chassahowitzka NWR 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 Units 4 and 5 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 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. Air emissions from PPS Units 4 and 5 SCCTs 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 NWR.

In conclusion, it is unlikely the projected air emission levels from PPS Units 4 and 5 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 Units 4 and 5. Opacity of the SCCTs exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the

SCCTs 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. Units 4 and 5 will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACTS

10.1 INTRODUCTION

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts, the Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase I Report, and EPA's Guideline on Air Quality Models. The CALPUFF model was employed in a refined mode using three years (1990, 1992, and 1996) of meteorology developed using the CALMET preprocessor program and specific receptors recommended by the National Park Service (NPS) for the Chassahowitzka NWR. The CALPUFF suite of programs, including the POSTUTIL and CALPOST post-processing programs, was employed to develop estimates of SCCT project impacts on the Chassahowitzka NWR for PSD increments, regional haze, and deposition.

10.2 SUMMARY

The CALMET/CALPUFF/CALPOST modeling assessment resulted in the following conclusions:

- Maximum SO_2, NO_2, and PM_{10} impacts at the Chassahowitzka NWR are projected to be well below the EPA Class I area significant levels for all pollutants and averaging periods. The critical averaging time and pollutant was determined to be the 24-hour average SO_2 impact. Maximum 24-hour average SO_2 impact on the Chassahowitzka NWR is projected to be 0.070 $\mu g/m^3$, or only 35 percent of the EPA PSD Class I significant impact level. The EPA PSD Class I significant impact levels were previously provided in Section 4.0, Table 4-3.
- Maximum change in light extinction coefficient (β_{ext}) at the Chassahowitzka NWR is projected to be 9.33 percent or a 0.892 change in deciview (dv). There were only two 24-hour maximum changes in light extinction that exceeded the Federal Land Manager (FLM) significance levels of a 5-percent

change in β_{ext} and 0.5 change in dv over the 3 years of meteorological data evaluated.

- Maximum total (wet and dry) sulfur deposition rate is projected to be 0.0048 kilograms per hectare per year (kg/ha/yr). The maximum nitrogen deposition rate is projected to be 0.0038 kg/ha/yr. These deposition impacts are only 48 and 38 percent of the FLM significance level of 0.01 kg/ha/yr for sulfur and nitrogen deposition, respectively.

10.3 MODEL SELECTION AND USE

The nearest Class I area to the PPS is the Chassahowitzka NWR, located approximately 120 km north of the project site. Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as the ISC3 models, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emission sources of interest, the EPA and FLM have initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The IWAQM was formed to coordinate the model development efforts of the EPA and FLMs.

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase I, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase II, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase I recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments.

The Phase II recommendations, issued in December 1998, are contained in the IWAQM Phase II Summary Report and Recommendations for Modeling Long Range Transport Impacts. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I Report dated December 2000. The Phase II IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendix A to Appendix W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants. The CALPUFF Modeling System consists of three main components: (a) CALMET, (b) CALPUFF, and (c) CALPOST. Each of these components is described in the following sections.

10.4 CALMET

CALMET is a meteorological model that develops hourly wind and temperature fields on a three-dimensional gridded modeling domain. The meteorological file produced by CALMET for use by CALPUFF also includes two-dimensional parameters such as mixing height, surface characteristics, and dispersion properties.

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file utilized by CALPUFF. The specific meteorological data used by the CALMET program include:

- Penn State/NCAR Mesoscale Model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed).
- Surface station weather data (windspeed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and wind speed at each sounding).
- Surface station precipitation data (precipitation rates).

- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, wind speed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux).

CALMET output files for calendar years 1990, 1992, and 1996 were obtained from the FDEP for use in assessing air quality impacts at the Chassahowitzka NWR. Further details regarding the meteorological data used in the CALMET program are provided in Section 10.5, Meteorological Data. An example CALMET output file is included in Appendix F. This output file shows all of the CALMET options employed by FDEP in developing their CALMET files for the Chassahowitzka NWR.

10.5 CALPUFF

CALPUFF is a transport and puff model that advects "puffs" of material from an emission source. These "puffs" undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also utilize non-gridded meteorological data similar to that used by a steady-state Gaussian model such as the ISC dispersion model. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models.

There are a number of optional CALPUFF input files that were not used for the Chassahowitzka NWR impact assessments. These include time-varying emission rates, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

CALPUFF generates output files consisting of hourly concentrations, deposition fluxes, and data required for visibility assessments for each receptor. These CALPUFF output files are subsequently processed by the POSTUTIL and CALPOST programs to provide impact summaries for the pollutants and averaging periods of interest.

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase II report and EPA's Guideline on Air Quality Models. Options selected include modeling of six species (SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}), chemical transformation using the MESOPUFF II scheme, wet removal, and a 5-km spacing meteorological and computational grid. The meteorological and computational grids include the PPS Units 4 and 5 emission sources and the Chassahowitzka NWR receptors. The current version of CALPUFF (Version 5.711A, Level 040716) was used in the Chassahowitzka NWR air quality impact assessments.

10.6 POSTUTIL

POSTUTIL is a post-processing program used to process the concentration generated by CALPUFF. POSTUTIL was used to consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes. The current version of POSTUTIL (Version 1.3, Level 030528) was used in the Chassahowitzka NWR air quality impact assessments.

10.7 CALPOST

CALPOST is a post-processing program used to process the concentration, deposition, and visibility files generated by CALPUFF. The CALPOST program was formulated to average and report pollutant concentrations or wet/dry deposition fluxes using the hourly data contained in the CALPUFF output files. CALPOST can produce summary tables of pollutant concentrations and depositions for each receptor for various averaging times and can develop ranked lists of these impacts. For visibility-related modeling (e.g., regional haze), CALPOST uses the CALPUFF generated pollutant concentrations to calculate extinction coefficients and other related indicators of visibility.

For visibility assessments, background conditions were estimated using "natural" background data (i.e., absent anthropogenic influences) and hourly relative humidity data. The

CALPOST program was then used to compute background extinction coefficients using the natural background data and the IWQAM recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the FLAG Phase I Report. Background light extinction Method 2 was selected to develop visibility impacts; this method uses speciated particulate concentration data and hourly relative humidity data. The current version of CALPOST (Version 5.51, Level 030709) was used in the Chassahowitzka NWR air quality impact assessments.

10.8 RECEPTOR GRID

Consistent with FLM modeling guidance, the CALPUFF receptor grid consisted of 113 discrete receptors, obtained from the NPS Web site, located throughout the Chassahowitzka NWR.

10.9 METEOROLOGICAL DATA

Processed CALMET meteorological data for calendar years 1990, 1992, and 1996 were obtained from the FDEP. Meteorological data used by the FDEP to develop the CALMET files consisted of mesoscale data (MM4 data for 1990 and 1992, and MM5 data for 1996) together with four upper air, five overwater, nine surface, and 32 precipitation stations located throughout the modeling domain.

10.10 MODELED EMISSION SOURCES

Modeled emission sources consisted Units 4 and 5 assuming oil firing at Case 4 conditions (i.e., rated load and 59°F ambient temperature). These operating conditions were selected because they result in the highest emission rates. Specific Unit 4 and 5 emission source characteristics used in the CALPUFF modeling assessments are summarized in Table 10-1.

Table 10-1. SCCT CALPUFF Emission Source Data

Parameter	Units	Value
Stack height	ft	114
Stack diameter	ft	18.0
Stack velocity	ft/sec	161.7
Stack temperature	°F	1,098
SO_2 emissions	lb/hr	101.5
H_2SO_4 emissions	lb/hr	11.7
NO_x emissions	lb/hr	319.0
PM_{10} emissions	lb/hr	34.0

Source: ECT, 2005.

10.11 MODEL RESULTS

Refined CALPUFF/CALPOST modeling results for Class I PSD increments, visibility, and deposition impacts at the Chassahowitzka NWR are discussed in the following sections.

10.11.1 PSD CLASS I INCREMENTS

Maximum annual NO_2, SO_2, and PM_{10} impacts are summarized on Tables 10-2, 10-3, and 10-4, respectively. Maximum 3- and 24-hour SO_2 impacts are summarized on Tables 10-5 and 10-6, respectively. Maximum 24-hour PM_{10} impacts are summarized on Table 10-7. These tables provide the highest impact for each pollutant and averaging period, the location of the highest impact, the time of occurrence for short-term (3- and 24-hour average) impacts, and the PSD Class I significant impact levels.

The critical pollutant and averaging period was determined to be the 24-hour average SO_2 impact. The maximum Unit 4 and 5 24-hour average SO_2 impact at the Chassahowitzka NWR is projected to be 0.070 $\mu g/m^3$, or only 35 percent of the EPA PSD Class I significant impact level.

The CALPUFF/CALPOST results demonstrate that maximum Unit 4 and 5 impacts at the Chassahowitzka NWR will be less than the EPA Class I PSD significant impact levels for all pollutants and averaging periods.

10.11.2 REGIONAL HAZE

Maximum 24-hour regional haze impacts are summarized on Table 10-8. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and PMC) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in Units of km and dv, and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be 11.01 percent, or slightly above the 5-percent FLM significant impact level. The project regional haze impacts are considered acceptable for the following reasons:

Table 10-2. CALPUFF Model Results—Annual NO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0035	0.0037	0.0047
PSD Class I significant impact ($\mu g/m^3$)	0.1	0.1	0.1
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	3.5	3.7	4.7
Receptor UTM/LCC (1996) Easting (km)	338.3	342.5	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	506.6
Distance from PPS (km)	118.0	123.7	122.4
Direction from PPS (Vector °)	327	331	317

Source: ECT, 2005.

Table 10-3. CALPUFF Model Results, Annual SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0032	0.0033	0.0042
PSD Class I significant impact ($\mu g/m^3$)	0.1	0.1	0.1
Exceed PSD Class I significant impact (Y/N)	N	N	N
Percent of PSD significant impact (%)	3.2	3.3	4.2
Receptor *UTM/LCC (1996) Easting (km)*	*339.9*	*339.9*	1,403.9
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,166.0	505.0
Distance from PPS (km)	117.1	117.1	119.9
Direction from PPS (Vector °)	328	328	317

Source: ECT, 2005.

Table 10-4. CALPUFF Model Results, Annual PM_{10}

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0014	0.0014	0.0019
PSD Class I significant impact ($\mu g/m^3$)	0.2	0.2	0.2
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	0.7	0.7	0.9
Receptor UTM/LCC (1996) Easting (km)	339.9	339.9	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,166.0	506.6
Distance from PPS (km)	117.1	117.1	122.4
Direction from PPS (Vector °)	328	328	317

Source: ECT, 2005.

Table 10-5. CALPUFF Model Results, 3-Hour SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.2856	0.3194	0.3140
PSD Class I significant impact ($\mu g/m^3$)	1.0	1.0	1.0
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	28.6	31.9	31.4
Receptor UTM/LCC (1996) Easting (km)	342.5	341.6	1,396.3
Receptor UTM/LCC (1996) Northing (km)	3,175.2	3,174.3	516.1
Distance from PPS (km)	123.7	123.4	133.2
Direction from PPS (Vector °)	331	330	318
Date of maximum impact	03/29/90	07/25/92	08/06/96
Julian date of maximum impact	88	207	217
Ending hour of maximum impact	1100	1100	0700

Source: ECT, 2005.

Table 10-6. CALPUFF Model Results, 24-Hour SO_2

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0629	0.0696	0.0561
PSD Class I significant impact ($\mu g/m^3$)	0.2	0.2	0.2
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	31.4	34.8	28.1
Receptor UTM/LCC (1996) Easting (km)	340.0	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,169.7	3,175.2	505.4
Distance from PPS (km)	120.3	123.7	118.6
Direction from PPS (Vector °)	329	330	318
Date of maximum impact	05/16/90	07/25/92	07/15/96
Julian date of maximum impact	136	207	197

Source: ECT, 2005.

Table 10-7. CALPUFF Model Results, 24-Hour PM_{10}

Maximum Annual Impacts	1990	1992	1996
Modeled Impact ($\mu g/m^3$)	0.0250	0.0273	0.0270
PSD Class I significant impact ($\mu g/m^3$)	0.3	0.3	0.3
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	8.3	9.1	9.0
Receptor UTM/LCC (1996) Easting (km)	340.0	342.5	1,402.0
Receptor UTM/LCC (1996) Northing (km)	3,169.7	3,175.2	506.6
Distance from PPS (km)	120.3	123.7	122.4
Direction from PPS (Vector °)	329	331	317
Date of maximum impact	05/16/90	07/25/92	05/18/96
Julian date of maximum impact	136	207	139

Source: ECT, 2005.

Table 10-8. CALPUFF Model Results, Regional Haze

Maximum Annual Impacts	Units	1990	1992	1996
B_{ext-s} - SO_4	Mm^{-1}	0.203	0.307	0.750
B_{ext-s} - NO_3	Mm^{-1}	0.291	0.303	1.314
B_{ext-s} - PMF	Mm^{-1}	0.033	0.050	0.090
B_{ext-s} - Total	Mm^{-1}	0.527	0.660	2.154
B_{ext-b} - background	Mm^{-1}	22.4	22.4	23.1
Visual range, background	km	175.0	175.0	169.5
Visual range, background	mi	108.7	108.8	105.3
Visual range, background	dv	8.0	8.0	8.4
Relative humidity factor (FRH)	-	4.29	4.28	5.09
Number of days with B_{ext} >5.0 %	-	0	0	2
Largest B_{ext} change	%	2.36	2.95	9.33
Date of largest B_{ext} change	-	07/04/90	07/19/92	01/16/96
NPS significant impact, B_{ext} change	%	5.00	5.00	5.00
Exceed NPS significant impact	Y/N	No	No	Yes
Percent of NPS significant impact	%	47.2	59.0	186.6
Number of days with delta deciview >0.5 %	-	0	0	1
Largest delta deciview change	-	0.233	0.291	0.892

Source: ECT, 2005.

- Only two 24-hour periods out of 1,097 modeled events (1990, 1992, and 1996) exceeded the FLM 5.0 percent guideline (i.e., the guideline was exceeded for only 0.18 percent of the modeled period).
- The regional haze impacts assumed continuous oil firing. For Units 4 and 5, oil-firing hours will be limited to no more than 750 hr/yr unit.
- The 5-percent FLM guideline is half of the level that is perceptible (i.e. increases in β_{ext} above 10 percent [equivalent to a dv change of 1.0]) are considered to be perceptible at the furthest extent of the visual range. Accordingly, the predicted Unit 4 and 5 maximum regional haze impact will not be perceptible in the Chassahowitzka NWR.
- The regional haze analysis compares project impacts with "natural" background (i.e., a theoretical background that would occur in the absence of all anthropogenic activities). This results in a natural background visual range of approximately 105 miles for the Chassahowitzka NWR. Other than nighttime celestial objects, there are no line-of-sight vistas in the coastal Chassahowitzka NWR that are near this visual range. For example, the theoretical line-of-sight for a 6-ft-tall person on the shoreline of the Gulf of Mexico is 3.2 miles due to the curvature of the earth.
- The 20 percent best visibility over the 1994 to 1998 period for the Chassahowitzka NWR was 18 dv or a visual range of 40 miles. A comparison of maximum Unit 4 and 5 regional haze impacts during oil firing with this actual background level results in a change in β_{ext} of 3.54 percent; well below perceptible levels.

10.12 DEPOSITION

Annual sulfur and nitrogen deposition rates are summarized on Tables 10-9 and 10-10, respectively. These tables provide the CALPUFF/POSTUTIL/CALPOST modeled total (wet and dry) deposition rates impact for nitrogen and sulfur in Units of $\mu g/m^2/s$ and kg/ha/yr. The maximum annual nitrogen and sulfur deposition rates of 0.0038 and 0.0048 kg/ha/yr, respectively, are well below the FLM guideline of 0.01 kg/ha/yr.

Table 10-9. CALPUFF Model Results, Total Nitrogen Deposition

Maximum Annual Impacts	1990	1992	1996
Total dry and wet nitrogen deposition ($\mu g/m^2/s$)	1.30E-05	2.04E-05	1.42E-05
Total dry and wet nitrogen deposition (kg/ha/yr)	0.0024	0.0038	0.0026
PSD Class I significant impact (kg/ha/yr)	0.01	0.01	0.01
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	23.9	37.6	26.1
Receptor UTM/LCC (1996) Easting (km)	339.9	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	505.4
Distance from PPS (km)	117.1	123.7	118.6
Direction from PPS (Vector °)	328	331	318

Source: ECT, 2005.

Table 10-10. CALPUFF Model Results, Total Sulfur Deposition

Maximum Annual Impacts	1990	1992	1996
Total dry and wet sulfur deposition ($\mu g/m^2/s$)	1.59E-05	2.60E-05	1.76E-05
Total dry and wet sulfur deposition (kg/ha/yr)	0.0029	0.0048	0.0033
PSD Class I significant impact (kg/ha/yr)	0.01	0.01	0.01
Exceed PSD Class I significant impact (Y/N)	No	No	No
Percent of PSD significant impact (%)	29.3	48.0	32.6
Receptor UTM/LCC (1996) Easting (km)	337.5	342.5	1,406.4
Receptor UTM/LCC (1996) Northing (km)	3,166.0	3,175.2	505.4
Distance from PPS (km)	118.5	123.7	118.6
Direction from PPS (Vector °)	327	331	318

Source: ECT, 2005.

10.13 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that Units 4 and 5 will result in ambient air quality impacts that are below the PSD Class I significant impact levels for all pollutants and all averaging periods. Accordingly, a multisource interactive assessment of air quality impacts with respect to the PSD Class I increments is not required.

As discussed above in Section 10.6, regional haze impacts are considered acceptable based on the conservative nature of the regional haze procedures and the Unit 4 and 5 project assumptions. Annual total nitrogen and sulfur deposition rates due to Units 4 and 5 are well below the FLM guideline of 0.01 kg/ha/yr.

Table 10-11 provides a summary of maximum Unit 4 and 5 Chassahowitzka NWR air quality impacts, the PSD Class I area EPA significant impact levels, and FLM guidelines.

Table 10-11. CALPUFF Model Chassahowitzka NWR Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.0037	0.1
PM_{10}	Annual	0.0014	0.2
	24-hour	0.028	0.3
SO_2	Annual	0.0033	0.1
	24-hour	0.070	0.2
	3-hour	0.32	1.0

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	0.0038	0.01
Sulfur	Annual	0.0048	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change B_{ext})	Significant Impact (% Change B_{ext})
Regional haze	24-Hour	10.01	5.0

Source: ECT, 2005.

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APPENDIX A

APPLICATION FOR AIR PERMIT—
LONG FORM

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:
- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:
- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **Polk Power Station**	
3. Facility Identification Number: **1050233**	
4. Facility Location...: Street Address or Other Locator: **9995 State Route 37 South** City: **Mulberry** County: **Polk** Zip Code: **33860-0775**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Raiza Calderon, Engineer —Air Programs**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601**
3. Application Contact Telephone Numbers... Telephone: **(813) 641-5261** ext. Fax: **(813) 641-5081**
4. Application Contact Email Address: **rcalderon@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	10/18/05
2. Project Number(s):	1050233-018-AC
3. PSD Number (if applicable):	PSD-FL-363
4. Siting Number (if applicable):	PA 92-32

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

Air Operation Permit

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

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

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

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

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

Application Comment

Tampa Electric Company (TEC) is planning to construct and operate two additional simple-cycle CTGs at the Polk Power Station (PPS). The PPS simple-cycle CTG project will consist of two, nominal 165-megawatt (MW) CTGs (designated as Units 4 and 5) 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 (equivalent to 4,380 hours per year at baseload) and 8.6 (equivalent to 750 hours per year at baseload) percent for natural gas and oil firing, respectively.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
011	Nominal 165 MW simple cycle gas turbine CTG-4	AC1A	N/A
012	Nominal 165 MW simple cycle gas turbine CTG-5	AC1A	

Application Processing Fee

Check one: ☐ Attached - Amount: $ ______________ ☒ Not Applicable

Note: The PPS is a Florida Power Plant Siting Act certified site. $10,000 Site Certification modification fee has been submitted to the FDEP Siting Coordination Office.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name: **Mark J. Hornick, General Manager**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601-0111**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(813) 288-1111** ext.**39988** Fax: **(863) 428-5927**
4.	Owner/Authorized Representative Email Address: **mjhornick@tecoenergy.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.* Mark J. Hornick — 10/17/05 Signature — Date

APPLICATION INFORMATION

Application Responsible Official Certification N/A

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

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ext. Fax:

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

   Signature Date

APPLICATION INFORMATION

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: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332-0444** ext. Fax: **(352) 332-6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.com**
5.	Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis

Signature (seal)

10/7/05

Date

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **402.45** North (km) **3,067.35**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/43/43** Longitude (DD/MM/SS) **81/59/23**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Mike Perkins, Environmental Coordinator**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **FL** Zip Code: **33601-0111**
3. Facility Contact Telephone Numbers: Telephone: **(813) 228-1111** ext.**39109** Fax: **(863) 428-5927**
4. Facility Contact Email Address: **mrperkins@tecoenergy.com**

Facility Primary Responsible Official N/A
Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

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

1.	☐ Small Business Stationary Source	☐ Unknown
2.	☐ Synthetic Non-Title V Source	
3.	☒ Title V Source	
4.	☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5.	☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6.	☐ Major Source of Hazardous Air Pollutants (HAPs)	
7.	☒ Synthetic Minor Source of HAPs	
8.	☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9.	☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10.	☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11.	☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12.	Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A**	**N**
SO2	**A**	**N**
CO	**A**	**N**
PM10	**A**	**N**
PM	**A**	**N**
SAM	**A**	**N**
VOC	**A**	**N**
PB	**B**	**N**
H114 (Mercury Compounds)	**B**	**N**
H015 (Arsenic Compounds)	**B**	**N**
H021 (Beryllium Compounds)	**B**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps N/A

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **Fig 2-1** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction or Modification: ☒ Attached, Document ID: **Section 2.0**
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **Att. A-2**
4.	List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
6.	Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
7.	Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:_____ ☒ Not Applicable
10.	Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_____ ☐ Not Applicable

? No Fugitives?

Additional Requirements for FESOP Applications N/A

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID: ☐ Not Applicable (no exempt units at facility)	

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

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

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
   Nominal 165 MW simple cycle combustion turbine – Unit 4

3. Emissions Unit Identification Number: **011**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**N/A**	**N/A**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7241(FA)**

10. Generator Nameplate Rating: **175.8 MW**

11. Emissions Unit Comment:

    Unit 4 will be fired primarily with pipeline quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Dry low-NO_x combustors (natural gas firing)** **Water injection (distillate fuel oil firing)**	
2. Control Device or Method Code(s):	**24 (dry low-NOx), 28 (water injection)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**	
2. Maximum Production Rate: **N/A**	
3. Maximum Heat Input Rate: **2,139 (HHV)** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr **N/A** tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **5,130*** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat rate is higher heating value (HHV) at 100 percent load, 20 °F, fuel-oil firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.** *** Maximum of 4,380 hours per year (natural gas firing) and 750 hours per year (distillate fuel oil firing).**	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT04**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **N/A**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**	

5. Discharge Type Code: **V**	6. Stack Height: **114** feet	7. Exit Diameter: **18** feet
8. Exit Temperature: **1,117** °F	9. Actual Volumetric Flow Rate: **2,393,587** acfm	10. Water Vapor: % **N/A**

11. Maximum Dry Standard Flow Rate: dscfm **N/A**	12. Nonstack Emission Point Height: feet **N/A**
13. Emission Point UTM Coordinates... **N/A** Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... **N/A** Latitude (DD/MM/SS) Longitude (DD/MM/SS)

15. Emission Point Comment:

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.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **1.913**	5. Maximum Annual Rate: **8,378.9**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: *	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **923** 1024 HHV 90
10. Segment Comment: 989 - HHV - 365 **Fuel heat content (field 9) represents lower heating value (LHV).** ***Sulfur content of fuel shall be less than 2 grains per 100 standard cubic foot.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with distillate fuel oil.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **14.724**	5. Maximum Annual Rate: **11,043**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **.05**	8. Maximum % Ash: **.01**	9. Million Btu per SCC Unit: **134**
10. Segment Comment: **Fuel heat content (field 9) represents lower heating value (LHV).**		

EMISSIONS UNIT INFORMATION
Section [1] of [2]

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - NOX	**024, 028**		**EL**
2 - CO			**EL**
3 – VOC			**NS**
4 – SO2			**EL**
5 – PM			**NS**
6 – PM10			**NS**

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: 73.5 **338.0** lb/hour **270.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **338.0 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 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 750 hrs/yr.

Case 1 20° 100% load

or 59° 68.8 lb/hr = 150.67 × 2 = 301.34 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **4**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10.5 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **68.8** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions **2** of **4**

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **42 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **319** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **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.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **68.8 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **68.8** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 7E and 19 annually. NOx CEMS RATA may be substituted for the annual compliance test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **319 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **319** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 7E and 19 annually. NOx CEMS RATA may be substituted for the annual compliance test. Annual testing only required if distillate fuel oil is used for more than 400 hours in the preceding 12-month period.**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to less stringent NOx limits of 40 CFR Part 60, Subpart GG (NSPS). Limit applicable for distillate fuel oil-firing.**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**	
3. Potential Emissions: 30.7 ~~97.7~~ lb/hour 63.072 ~~113.4~~ tons/year		4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year		
6. Emission Factor: 97.7 **LB/HR** Reference: **GE Data**		7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 36.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 92.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

20°F 100%

NG 59° 28.8 lb/hr = 63.072
= 126.144 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **9.0 ppmvd @ 15% O_2 (24-hour block average)**	5. Equivalent Allowable Emissions: **36.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **20.0 ppmvd @ 15% O_2 (24-hour block average)**	4. Equivalent Allowable Emissions: **92.2** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **CO CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate oil-firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: 36.0 **lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **36.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 10 and 19 annually. CO CEMS RATA may be substituted for the annual compliance test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: 92.2 **lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **92.2** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA Reference Methods 10 and 19 annually. CO CEMS RATA may be substituted for the annual compliance test. Annual testing only required if distillate fuel oil is used for more than 400 hours in the preceding 12-month period.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **107.8** lb/hour **59.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **107.8 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 9.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 101.5 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

10.2 @ 20° = 23 x 2 = 46

9.5 @ 59° = 20.8 x 2 = 41.61 TPY

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

H_2SO_4 1.1 lb/hr = 2.4 TPY x 2 = 4.8/8 TPY

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **Pipeline Quality Natural Gas**	6. Equivalent Allowable Emissions: **9.5** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **Use of pipeline quality natural gas (sulfur content less than 2 grains per 100 standard cubic foot). Natural gas sulfur content monitored using 40 CFR Part 75 procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for natural gas-firing.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.05 weight % S oil**	4. Equivalent Allowable Emissions: **101.5** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **Use of distillate fuel oil containing no more than 0.05 weight percent sulfur. Distillate fuel oil sulfur content monitored using applicable 40 CFR Part 75 Appendix D procedures.**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **7.6** lb/hour **8.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **7.6 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 20°F, fuel oil-firing case. Annual emissions based on 2.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 7.2 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

3.0 @ 20° = 6.57 x 2 = 13.14

2.8 @ 59° = 6.132 x 2 = 12.264

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS – N/A

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

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	7. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	8. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

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

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM/PM$_{10}$**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **34.0** lb/hour **52.2** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **34.0 LB/HR** Reference: **GE Data**	7. Emissions Method Code: **5**

8. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 59°F, fuel oil-firing case. Annual emissions based on 18.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 4,380 hrs/yr and 34.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 750 hrs/yr.

PM/PM$_{10}$ emissions include filterable and condensible particulate.

18 39.42 x 2 = 78.84

9. Pollutant Potential/Estimated Fugitive Emissions Comment:

Maximum of 4,380 hours per year (natural gas-firing) and 750 hours per year (distillate fuel oil-firing).

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS – N/A

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **18.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA RM 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for gas-firing.**	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10 % Opacity**	4. Equivalent Allowable Emissions: **34.0** lb/hour **N/A** tons/year **(at ISO conditions)**
5. Method of Compliance: **EPA RM 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: *	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **N/A**	
5. Visible Emissions Comment: *** Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided best operation practices are adhered to and the duration of excess emissions shall be minimized.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
6. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific monitor information not currently available.**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Specific monitor information not currently available.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Fig. 2-3** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Att. A-3** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 5.0** ☐ Previously Submitted, Date _____

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

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

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

   ☐ To be Submitted, Date (if known):__________
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☒ Not Applicable

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

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **Section 6.0** ☐ Not Applicable	
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: _____ ☐ Not Applicable **(To be provided)**	

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

1. Identification of Applicable Requirements ☐ Attached, Document ID:	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____	☐ Not Applicable
3. Alternative Methods of Operation ☐ Attached, Document ID:	☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____	☐ Not Applicable
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ☐ Previously Submitted, Date:_____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____ ☐ Not Applicable	

Additional Requirements Comment

NOTE:

POLK POWER STATION EMISSION UNITS 4 AND 5 ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 011 (UNIT 4) IS ALSO APPLICABLE TO EU 012 (UNIT 5).

EMISSIONS UNIT INFORMATION PROVIDED IN SECTION III.A THROUGH III. I FOR UNIT 4 ALSO APPLY TO UNIT 5, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

APPENDIX A-1

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from Polk Power Station operations include:

- Vehicular traffic on unpaved roads and production pads.
- Wind-blown dust from yard areas.
- Periodic abrasive blasting.

The following techniques will be used to control unconfined particulate matter emissions on an as needed basis:

- Chemical or water application to unpaved roads and unpaved yard areas.
- Paving and maintenance of roads, parking areas and yards.
- Landscaping or planting of vegetation.
- Confining abrasive blasting where possible.
- Other techniques, as necessary.

APPENDIX A-2

REGULATORY APPLICABILITY ANALYSES

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 60 - Standards of Performance for New Stationary Sources.				
Subpart A - General Provisions				
Notification and Recordkeeping	§60.7(b) - (h)		Units 4-5	General recordkeeping and reporting requirements.
Performance Tests	§60.8		Units 4-5	Conduct performance tests as required by EPA or FDEP. (**potential future requirement**)
Compliance with Standards	§60.11(a) thru (d), and (f)		Units 4-5	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		Units 4-5	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		Units 4-5	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		Units 4-5	General procedures regarding reporting deadlines.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Standards for Nitrogen Oxides	§60.332(a)(1) and (b), (f), and (I)		Units 4-5	Establishes NO_x limit of 75 ppmv at 15% (with corrections for heat rate and fuel bound nitrogen) for electric utility stationary gas turbines with peak heat input greater than 100 MMBtu/hr.
Standards for Sulfur Dioxide	§60.333		Units 4-5	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Monitoring Requirements	§60.334(a)	X	Units 4-5	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and ©)		Units 4-5	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		Units 4-5	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to Polk Power Station Units 4 and 5.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to the Polk Power Station Units 4 and 5.
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX		X		None of the listed NESHAPS' contain requirements which are applicable to the Polk Power Station Units 4 and 5.

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)		Units 4-5	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		Units 4-5	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), ©), and (d)		Units 4-5	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		Units 4-5	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.

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 D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		Units 4-5	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the Polk Power Station Units 4 and 5.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		Units 4-5	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 ©)		Units 4-5	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		Units 4-5	Requirement to submit an annual compliance report. **(future requirement)**

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
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		Units 4-5	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		Units 4-5	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		Units 4-5	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)		Units 4-5	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)		Units 4-5	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		Units 4-5	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		Units 4-5	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20©)		Units 4-5	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		Units 4-5	General QA/QC requirements (excluding opacity).

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
Reference Test Methods	§75.22		Units 4-5	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		Units 4-5	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), ©)		Units 4-5	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		Units 4-5	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and ©)		Units 4-5	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		Units 4-5	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), ©), and (d)(1)		Units 4-5	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		Units 4-5	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55©)		Units 4-5	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		Units 4-5	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		Units 4-5	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.

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 G - Reporting Requirements				
General Provisions	§75.60		Units 4-5	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and ©)		Units 4-5	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.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		Units 4-5	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)		Units 4-5	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.

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
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		Units 4-5	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)		Units 4-5	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)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		Units 4-5	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		Polk Power Station Units 4 and 5will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Polk Power Station 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.

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
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Polk Power Station will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Polk Power Station Units 4 and 5.will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Polk Power Station 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.
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.

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
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		Polk Power Station 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		Polk Power Station personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
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.

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
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 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since Units 4 and 5 will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Hydrogen Storage	Subject to provisions of 40 CFR Part 68 due to hydrogen storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to Polk Power Station Units 4 and 5.

Source: ECT, 2005.

APPENDIX A-2

REGULATORY APPLICABILITY ANALYSES

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 Polk Power Station Units 4 and 5.
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)16.,(b)39., (c), (d), and (e), F.A.C.			CT 3A-3B	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.			CT 3A-3B	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 Polk Power Station Units 4 and 5.
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 Polk Power Station Units 4 and 5.
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	62-210.700(2) and (3), F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
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)**.

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(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 Polk Power Station Units 4 and 5
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.
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 Polk Power Station Units 4 and 5.
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)**

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
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.			CT 3A-3B	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.
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)**.

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
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.
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.			CT 3A-3B	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.			CT 3A-3B	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)**

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
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.			CT 3A-3B	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.			CT 3A-3B	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.			CT 3A-3B	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.
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.

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
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 Polk Power Station Units 4 and 5.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to Polk Power Station Units 4 and 5.

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 Polk Power Station Units 4 and 5.
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 nonattainment 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 located in a PM air quality maintenance area. However, there are no limits applicable to CTs.
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 Polk Power Station Units 4 and 5.
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, 2005.

APPENDIX A-3

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 (HHV)	1,020 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, 2005.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Specific gravity @ 60EF (maximum)	0.876
Viscosity, saybolt (SUS) @ 100EF	
Minimum	40.2
Maximum	32.6
Flash point, EF (minimum)	100
Pour point, EF (minimum)	0
Minimum gross heating value, Btu/lb	
LHV	18,550
HHV	19,626
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, 2005.

APPENDIX B

EMISSION RATE CALCULATIONS

Table B-1. TEC Polk Power Station, SCCT Units 4 and 5
CT Operating Scenarios - General Electric 7241FA CT

Case	Ambient Temperature (oF)	Load (%)	Simple Cycle Units 4 and 5	Annual Profile (hr/yr)	Natural Gas Firing	Fuel Oil Firing
1	20	100	X		X	X
2	20	75	X		X	X
3	20	50	X		X	X
4	59	100	X	4,380 (gas), 750 (oil)	X	X
5	59	75	X		X	X
6	59	50	X		X	X
7	90	100	X		X	X
8	90	75	X		X	X
9	90	50	X		X	X

SCCT - simple cycle combustion turbine
CT - combustion turbine

Sources: TEC, 2005.
ECT, 2005.

Table B-2. TEC Polk Power Station, SCCT Units 4 and 5
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)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	18.0	2.27	10.2	1.28	1.2	0.15	0.0306	0.00386
	2	75	18.0	2.27	8.2	1.03	0.9	0.12	0.0245	0.00309
	3	50	18.0	2.27	6.5	0.82	0.7	0.09	0.0196	0.00247
59	4	100	18.0	2.27	9.5	1.20	1.1	0.14	0.0286	0.00361
	5	75	18.0	2.27	7.7	0.97	0.9	0.11	0.0232	0.00292
	6	50	18.0	2.27	6.2	0.78	0.7	0.09	0.0186	0.00235
90	7	100	18.0	2.27	8.8	1.10	1.0	0.13	0.0264	0.00332
	8	75	18.0	2.27	7.2	0.91	0.8	0.10	0.0216	0.00272
	9	50	18.0	2.27	5.8	0.73	0.7	0.08	0.0174	0.00220
		Maximums	**18.0**	**2.27**	**10.2**	**1.28**	**1.2**	**0.15**	**0.0306**	**0.0039**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC[6] (ppmvd)[5]	VOC[6] (lb/hr)	VOC[6] (g/sec)
20	1	100	10.5	73.5	9.26	7.2	30.3	3.82	1.2	3.0	0.38
	2	75	10.5	58.3	7.35	7.1	23.9	3.02	1.1	2.1	0.26
	3	50	10.5	45.5	5.73	7.4	19.9	2.50	1.2	1.9	0.23
59	4	100	10.5	68.8	8.67	7.2	29.7 28.8	3.63	1.2	2.8	0.35
	5	75	10.5	54.8	6.91	7.2	23.0	2.89	1.1	1.9	0.24
	6	50	10.5	43.2	5.44	7.6	19.0	2.40	1.2	1.7	0.21
90	7	100	10.5	63.0	7.94	7.1	25.7	3.24	1.2	2.6	0.33
	8	75	10.5	51.3	6.47	7.3	21.7	2.74	1.2	2.1	0.26
	9	50	10.5	40.8	5.15	7.8	18.4	2.31	1.2	1.7	0.21
		Maximums	**10.5**	**73.5**	**9.26**	**7.8**	**30.3**	**3.82**	**1.2**	**3.0**	**0.38**

[1] Filterable and condensible PM, excluding H_2SO_4 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] Table 1.4-2, AP-42, EPA, May 1998.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2005.
GE, 1998.

4.1 ppm ≈ .0092 lbs/mmBtu
= 16.87 lb/hr

?
.016

5.35 ppm
= .012 lb/mmBtu = 22.37 lb/hr
\\ 49 TPY

22.37 lb/hr

Table B-3. TEC Polk Power Station, SCCT Units 4 and 5
CT Hourly Emission Rates - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-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)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	34.0	4.28	107.8	13.58	12.4	1.56	0.104	0.0131
	2	75	34.0	4.28	87.4	11.02	10.0	1.27	0.084	0.0106
	3	50	34.0	4.28	68.2	8.59	7.8	0.99	0.067	0.0084
59	4	100	34.0	4.28	101.5	12.79	11.7	1.47	0.098	0.0123
	5	75	34.0	4.28	82.5	10.40	9.5	1.19	0.079	0.0100
	6	50	34.0	4.28	64.9	8.18	7.5	0.94	0.063	0.0079
90	7	100	34.0	4.28	92.3	11.63	10.6	1.34	0.093	0.0117
	8	75	34.0	4.28	75.6	9.53	8.7	1.09	0.073	0.0092
	9	50	34.0	4.28	59.8	7.54	6.9	0.87	0.058	0.0073
		Maximums	**34.0**	**4.28**	**107.8**	**13.58**	**12.4**	**1.56**	**0.104**	**0.0131**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC[6] (ppmvd)[5]	VOC[6] (lb/hr)	VOC[6] (g/sec)
20	1	100	42.0	338.0	42.59	20.0	97.7	12.31	2.8	7.6	0.96
	2	75	42.0	272.0	34.27	20.0	78.5	9.89	2.7	5.8	0.73
	3	50	42.0	210.0	26.46	20.0	60.6	7.64	2.8	5.1	0.64
59	4	100	42.0	319.0	40.19	20.0	92.2	11.62	2.8	7.2	0.91
	5	75	42.0	257.0	32.38	20.0	74.1	9.34	2.7	5.7	0.72
	6	50	42.0	200.0	25.20	20.0	57.7	7.28	2.9	4.6	0.58
90	7	100	42.0	290.0	36.54	20.0	84.3	10.62	2.8	6.5	0.82
	8	75	42.0	235.0	29.61	20.0	67.9	8.55	2.8	5.6	0.71
	9	50	42.0	184.0	23.18	20.0	53.2	6.70	3.0	4.5	0.57
		Maximums	**42.0**	**338.0**	**42.59**	**20.0**	**97.7**	**12.31**	**3.0**	**7.6**	**0.96**

[1] Filterable and condensible PM, excluding H_2SO_4 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] Based on 1.0 ppmw lead content of fuel oil.
[5] Corrected to 15% O_2.
[6] Non-methane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2005.
GE, 1998.

Table B-4. TEC Polk Power Station, SCCT Units 4 and 5
CT Emission Rates - General Electric 7241FA CT
Natural Gas-Firing: Hazardous Air Pollutants

Maximum Hourly Heat Input: (Case 1)	1,960	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,834	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	4,380	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	HAP Emissions (Per CT) (lb/hr)[2]	(g/s)[2]	(ton/yr)[3]	HAP Emissions Units 4 & 5 (ton/yr)[4]
1,3-Butadiene	4.30E-08	8.43E-05	1.06E-05	1.73E-04	3.45E-04
Acetaldehyde	4.00E-06	7.84E-03	9.88E-04	1.61E-02	3.21E-02
Acrolein	6.40E-07	1.25E-03	1.58E-04	2.57E-03	5.14E-03
Benzene	1.20E-06	2.35E-03	2.96E-04	4.82E-03	9.64E-03
Ethylbenzene	3.20E-06	6.27E-03	7.90E-04	1.29E-02	2.57E-02
Formaldehyde[4]	2.19E-04	4.29E-01	5.40E-02	8.78E-01	1.76E+00
Naphthalene	1.30E-07	2.55E-04	3.21E-05	5.22E-04	1.04E-03
Polycyclic Aromatic Hydrocarbons (PAH)	2.20E-07	4.31E-04	5.43E-05	8.84E-04	1.77E-03
Propylene Oxide	2.90E-06	5.68E-03	7.16E-04	1.16E-02	2.33E-02
Toluene	1.30E-05	2.55E-02	3.21E-03	5.22E-02	1.04E-01
Xylene	6.40E-06	1.25E-02	1.58E-03	2.57E-02	5.14E-02

[1] HAP emission factors for lean premix (LPM) combustion are based on EPA AP-42, Section 3.1, Table 3.1-3 April, 2000 diffusion flame emission factors and 90% reduction for LPM combustion.
[2] Hourly (lb/hr and g/s) emission rates based on Case 1 (100% load, 0°F ambient temperature).
[3] Annual (ton/yr) emission rates based on Case 4 (100% load, 59°F ambient temperature).
[4] Formaldehyde emission factor based on GE guarantee of 91 parts per billion by volume dry (ppbvd), corrected to 15% O_2.

Sources: ECT, 2005.
GE, 2005.

Table B-5. TEC Polk Power Station, SCCT Units 4 and 5
CT Emission Rates - General Electric 7241FA CT
Distillate Fuel Oil-Firing: Hazardous Air Pollutants

Maximum Hourly Heat Input: (Case 1)	2,139	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	2,015	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	750	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	HAP Emissions (Per CT) (lb/hr)[2]	(g/s)[2]	(ton/yr)[3]	HAP Emissions Units 4 & 5 (ton/yr)[4]
1,3-Butadiene	1.60E-05	3.42E-02	4.31E-03	1.21E-02	2.42E-02
Arsenic	1.10E-05	2.35E-02	2.96E-03	8.31E-03	1.66E-02
Benzene	5.50E-05	1.18E-01	1.48E-02	4.16E-02	8.31E-02
Beryllium	3.10E-07	6.63E-04	8.35E-05	2.34E-04	4.68E-04
Cadmium	4.80E-06	1.03E-02	1.29E-03	3.63E-03	7.25E-03
Chromium	1.10E-05	2.35E-02	2.96E-03	8.31E-03	1.66E-02
Formaldehyde[4]	2.31E-04	4.94E-01	6.22E-02	1.74E-01	3.49E-01
Lead	1.40E-05	2.99E-02	3.77E-03	1.06E-02	2.12E-02
Manganese	7.90E-04	1.69E+00	2.13E-01	5.97E-01	1.19E+00
Mercury	1.20E-06	2.57E-03	3.23E-04	9.07E-04	1.81E-03
Naphthalene	3.50E-05	7.49E-02	9.43E-03	2.64E-02	5.29E-02
Nickel	4.60E-06	9.84E-03	1.24E-03	3.48E-03	6.95E-03
PAH	4.00E-05	8.55E-02	1.08E-02	3.02E-02	6.04E-02
Selenium	2.50E-05	5.35E-02	6.74E-03	1.89E-02	3.78E-02

[1] AP-42 Section 3.1, Tables 3.1-4. And 3.1-5., EPA April, 2000.
[2] Hourly (lb/hr and g/s) emission rates based on Case 1 (100% load, 0°F ambient temperature).
[3] Annual (ton/yr) emission rates based on Case 4 (100% load, 59°F ambient temperature).
[4] Formaldehyde emission factor based on GE guarantee of 91 parts per billion by volume dry (ppbvd), corrected to 15% O_2.

Sources: ECT, 2005.
GE, 2005.

Table B-6. TEC Polk Power Station, SCCT Units 4 and 5 CT Emission Rates - General Electric 7241FA CT Hazardous Air Pollutants; Annual Summary

Pollutant	HAP Emissions Units 4 & 5		
	Gas-Firing (ton/yr)	Oil-Firing (ton/yr)	Totals (ton/yr)
1,3-Butadiene	0.00035	0.02418	0.02452
Acetaldehyde	0.03213	N/A	0.03213
Acrolein	0.00514	N/A	0.00514
Arsenic	N/A	0.01662	0.01662
Benzene	0.00964	0.08311	0.09275
Beryllium	N/A	0.00047	0.00047
Cadmium	N/A	0.00725	0.00725
Chromium	N/A	0.01662	0.01662
Ethylbenzene	0.02571	N/A	0.02571
Formaldehyde	**1.75696**	0.34874	**2.10569**
Lead	N/A	0.02116	0.02116
Manganese	N/A	**1.19383**	1.19383
Mercury	N/A	0.00181	0.00181
Naphthalene	0.00104	0.05289	0.05394
Nickel	N/A	0.00695	0.00695
PAH	0.00177	0.06045	0.06221
Propylene Oxide	0.02330	N/A	0.02330
Selenium	N/A	0.03778	0.03778
Toluene	0.10443	N/A	0.10443
Xylene	0.05141	N/A	0.05141
Maximum Individual HAP	1.76	1.19	2.11
Maximum Total HAPs	2.01	1.87	3.88

Note: Maximum individual HAPs shown in bold-face font.

Sources: ECT, 2005.
GE, 2005.

Table B-7. TEC Polk Power Station, SCCT Units 4 and 5 Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates NO$_x$ (lb/hr)	NO$_x$ (tpy)	CO (lb/hr)	CO (tpy)	VOC (lb/hr)	VOC (tpy)
Unit 4	4 - NG	4,380	68.8	150.7	36.0	78.8	2.8	6.2
Unit 5	4 - NG	4,380	68.8	150.7	36.0	78.8	2.8	6.2
Unit 4	4 - Oil	750	319.0	119.6	92.2	34.6	7.2	2.7
Unit 5	4 - Oil	750	319.0	119.6	92.2	34.6	7.2	2.7
		Totals	**N/A**	**540.7**	**N/A**	**226.8**	**N/A**	**17.7**

Source	Case	Annual Operations (hrs/yr)	Emission Rates PM/PM$_{10}$ (lb/hr)	PM/PM$_{10}$ (tpy)	SO_2 (lb/hr)	SO_2 (tpy)	H_2SO_4 (lb/hr)	H_2SO_4 (tpy)	Lead (lb/hr)	Lead (tpy)
Unit 4	4 - NG	4,380	18.0	39.4	9.5	20.9	1.09	2.4	0.029	0.063
Unit 5	4 - NG	4,380	18.0	39.4	9.5	20.9	1.09	2.4	0.029	0.063
Unit 4	4 - Oil	750	34.0	12.8	101.5	38.1	11.66	4.4	0.098	0.037
Unit 5	4 - Oil	750	34.0	12.8	101.5	38.1	11.66	4.4	0.098	0.037
		Totals	**N/A**	**104.3**	**N/A**	**117.9**	**N/A**	**13.5**	**N/A**	**0.199**

Sources: GE, 1998.
ECT, 2005.
TEC, 2005.

Table B-8. TEC Polk Power Station, SCCT Units 4 and 5
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, 2005.
GE, 1998.

Table B-9A. TEC Polk Power Station, SCCT Units 4 and 5
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
	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)		1,053.08	981.13	910.01	839.46	801.53	751.61	689.69	664.87	630.85
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, 2005.
GE, 1998.

Table B-9B. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Natural Gas-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	2,501,394	2,393,587	2,279,099	2,032,504	1,982,448	1,911,361	1,720,962	1,689,336	1,636,463
Velocity (fps)	163.8	156.8	149.3	133.1	129.8	125.2	112.7	110.6	107.2
Velocity (m/s)	49.9	47.8	45.5	40.6	39.6	38.2	34.4	33.7	32.7
SCFM, Dry[1]	791,825	733,365	668,502	631,260	599,825	552,825	519,904	498,776	465,339
ACFM (15% O_2, Dry)	2,861,380	2,736,637	2,560,494	2,316,258	2,227,959	2,110,800	1,887,869	1,822,012	1,720,949

Sources: ECT, 2005.
GE, 1998.

Table B-10A. TEC Polk Power Station, SCCT Units 4 and 5
CT Exhaust Data - General Electric 7241FA CT (Per CT)
Distillate Fuel Oil-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	0.87	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
	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)		1,085.99	1,021.29	941.25	811.85	784.24	751.05	677.70	667.94	645.91
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, 2005.
GE, 1998.

Table B-10B. TEC Polk Power Station, SCCT Units 4 and 5
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	2,565,225	2,468,510	2,338,219	2,066,743	2,012,963	1,945,329	1,734,167	1,712,182	1,666,850
Velocity (fps)	168.0	161.7	153.1	135.4	131.8	127.4	113.6	112.1	109.2
Velocity (m/s)	51.2	49.3	46.7	41.3	40.2	38.8	34.6	34.2	33.3
SCFM, Dry[1]	793,504	742,956	677,155	590,027	569,184	541,040	498,086	490,465	470,428
ACFM (15% O_2, Dry)	3,272,679	3,146,844	2,923,523	2,833,193	2,693,164	2,474,511	2,205,243	2,098,885	1,936,533

Sources: ECT, 2005.
GE, 1998.

Table B-11. TEC Polk Power Station, SCCT Units 4 and 5
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[1] (MMBtu/hr)	~~1,960~~ 1894	1,834 1772	1,688	1,572	1,487	1,383	1,255	1,193 1153	1,116
Fuel Rate (lb/hr)	84,521	79,074	72,781	67,796	64,104	59,624	54,119	51,448	48,113
Fuel Rate (10^6 ft^3/hr)	1.913	1.790	1.647	1.534	1.451	1.349	1.225	1.164	1.089
Fuel Rate (lb/sec)	23.478	21.965	20.217	18.832	17.807	16.562	15.033	14.291	13.365

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[1] (MMBtu/hr)	2,139 2,067	2,015	1,832	1,735	1,638	1,501	1,353	1,288	1,187
Fuel Rate (lb/hr)	107,764	101,532	92,336	87,438	82,517	75,612	68,180	64,922	59,832
Fuel Rate (10^3 gal/hr)	14.742	13.889	12.631	11.961	11.288	10.343	9.327	8.881	8.185
Fuel Rate (lb/sec)	29.935	28.203	25.649	24.288	22.921	21.003	18.939	18.034	16.620

[1] Includes a 3.5% margin to account for heat rate degradation over time.

Sources: ECT, 2005.
GE, 1998.

MMBtu/hr

1894
66.29

APPENDIX C

DISPERSION MODELING FILES

Polk Power Station
Units 4 and 5 Simple Cycle Combustion Turbine Project
Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
ISC Met Data	5	spgXX.asc	St.Petersburg/Clearwater< FL surface meteorological data
		XX = 92 - 96	Ruskin, FL upper air meteorological data
GEP Files	1	45.bpi	Building Profile Input Program (BPIP) input file
	1	45.bpo	Building Profile Input Program (BPIP) output file - brief
	1	45.sum	Building Profile Input Program (BPIP) output file - detailed
Subtotal Files	3		
ISC Files	10	XXy.inp	ISC input files, 1992-1996
	10	XXy.out	ISC output files, 1992-1996
		y = g (gas), o (oil)	
		XX = 92 - 96	
Subtotal Files	20		
CALPUFF Files	3	oilXX.inp	CALPUFF input files for 1990, 1992, and 1996
	3	oilXX.con	CALPUFF output concentration files for 1990, 1992, and 1996
	3	oilXX.lst	CALPUFF output list files for 1990, 1992, and 1996
	3	oilXXdf.dat	CALPUFF output dry deposition flux files for 1990, 1992, and 1996
	3	oilXXwf.dat	CALPUFF output wet deposition flux files for 1990, 1992, and 1996
Subtotal Files	15		
POSTUTIL Files	3	postutilXX.inp	POSTUTIL HNO_3/NO_3 partitioning input files for 1990, 1992, and 1996
	3	oilXXp.lst	POSTUTIL HNO_3/NO_3 partitioning output list files for 1990, 1992, and 1996
	3	oilXXp.con	CALPUFF output concentration files for 1990, 1992, and 1996 (processed for HNO_3/NO_3 partitioning)
	3	utilXXdep.inp	POSTUTIL total deposition flux input files for 1990, 1992, and 1996
	3	XXtflx.lst	POSTUTIL total deposition flux output list files for 1990, 1992, and 1996
	3	XXtflx.con	CALPUFF output total deposition flux files for 1990, 1992, and 1996 (processed for total S and N deposition)
		XX = 90, 92, 96	
Subtotal Files	18		
CALPOST Files	3	XXso2.poi	CALPOST SO_2 input files for 1990, 1992, and 1996
	3	XXso2.lst	CALPOST SO_2 output list files for 1990, 1992, and 1996
	3	XXno2.poi	CALPOST NO_2 input files for 1990, 1992, and 1996
	3	XXno2.lst	CALPOST NO_2 output list files for 1990, 1992, and 1996
	3	XXpm.poi	CALPOST PM input files for 1990, 1992, and 1996
	3	XXpm.lst	CALPOST PM output list files for 1990, 1992, and 1996
	3	XXvis.poi	CALPOST regional haze input files for 1990, 1992, and 1996
	3	XXvis.lst	CALPOST regional haze output list files for 1990, 1992, and 1996
	3	XXndep.poi	CALPOST nitrogen deposition input files for 1990, 1992, and 1996
	3	XXndep.pol	CALPOST nitrogen deposition output list files for 1990, 1992, and 1996
	3	XXsdep.pol	CALPOST nitrogen deposition input files for 1990, 1992, and 1996
	3	XXsdep.pol	CALPOST nitrogen deposition output list files for 1990, 1992, and 1996
Subtotal Files	36		
RH Files	1	rh.zip	CALMET relative humidity files for 1990, 1992, and 1996 (compressed)
Total Files	98		

Source: ECT, 2005.

APPENDIX D

PROPOSED AIR CONSTRUCTION PERMIT
(To be submitted as an addendum)

TAMPA ELECTRIC

POLK POWER STATION
UNITS 4 AND 5

Dispersion Modeling Files

ECT No.
051095-0100

ECT
Environmental Consulting & Technology, Inc.

October 2005