Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

Colleen M. Castille
Secretary

May 8, 2006

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
P. O. Box 25287
Denver, Colorado 80225

RE: Oleander Power Project, Unit 5
0090180-003-AC, PSD-FL-377

Dear Mr. Bunyak:

Enclosed for your review and comment is a PSD application submitted by Oleander Power Project, L.P., to install one additional simple-cycle combustion turbine generator (Unit 5) at its existing Oleander Power Project facility in Cocoa, Brevard County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Cindy Mulkey, Review Engineer, at 850/921-8968.

Sincerely,

Patty Adams

for A. A. Linero, P.E., Administrator
South Permitting Section

AAL/pa

Enclosure

cc: C. Mulkey

Department of
Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

May 11, 2006

Mr. Gregg M. Worley, Chief
Air Permits Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303-8960

RE: Oleander Power Project, Unit 5
0090180-003-AC, PSD-FL-377

Dear Mr. Worley:

Enclosed for your review and comment is a PSD application submitted by Oleander Power Project, L.P., to install one additional simple-cycle combustion turbine generator (Unit 5) at its existing Oleander Power Project facility in Cocoa, Brevard County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/921-9533. If you have any questions, please contact Cindy Mulkey, Review Engineer, at 850/921-8968.

Sincerely,

Patty Adams

for A. A. Linero, P.E., Administrator
South Permitting Section

AAL/pa

Enclosure

cc: C. Mulkey

FM: Dep Air Resource Mgmt
P. Adams
Director Office Ste 23
111 S Magnolia Dr
Tallahassee, FL 32301
UNITED STATES Phone: 850--92-1-9505

EXP+

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To: NATIONAL PARK SERVICE
MR. JOHN BUNYAK
12795 W. ALAMEDA PARKWAY
AIR DIVISION
LAKEWOOD, CO 80228
UNITED STATES

Sender's ref 37550201000 A7 AP255

POSTCODE: **80228**

TEL: 303-966-2818

Time **10:30**

Description: PSD-FL-377 application

Weight: 3 lbs for 1 pcs
Date: 2006-05-08

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Lakewood, CO 80228
UNITED STATES

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Phone#: 303-966-2818

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 16.07
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ORIGIN: TLH

Sender's ref 37550201000 A7 AP255

To: U.S. EPA REGION 4
MR. GREGG M. WORLEY
61 FORSYTH STREET
AIR PERMITS SECTION
ATLANTA, GA 30303
UNITED STATES

POSTCODE: 30303

TEL: 404-562-9141

Day 12FR

Description: PSD-FL-377 application

Weight: 3 lbs for 1 pcs
Date: 2006-05-11

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		Dimensions:	0 x 0 x 0
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		Service Level:	Ground (Est. delivery in 1 business day(s))
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Phone#:	404-562-9141		
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To: DEP CENTRAL DISTRICT
MR. ALAN ZAHM
3319 MAGUIRE BLVD.
225
ORLANDO, FL 32803
UNITED STATES

TEL: 407-893-3334

Sender's ref: 37550201000 A7 AP255

POSTCODE: **32803**

Day **12FR**

Description: PSD-FL-377 application

Weight: 3 lbs for 1 pcs
Date: 2006-05-11

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To(Company):
DEP Central District
225
3319 Maguire Blvd.

Orlando, FL 32803
UNITED STATES

Attention To: Mr. Alan Zahm
Phone#: 407-893-3334

Sent By: P. Adams
Phone#: 850-921-9505

Rate Estimate: 3.07
Protection: Not Required
Description: PSD-FL-377 application

Weight (lbs.): 3
Dimensions: 0 x 0 x 0

Ship Ref: 37550201000 A7 AP255
Service Level: Ground (Est. delivery in 1 business day(s))

Special Svc:

Date Printed: 5/11/2006
Bill Shipment To: Sender
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EXPRESS

OLEANDER POWER PROJECT

SIMPLE-CYCLE COMBUSTION TURBINE GENERATOR UNIT 5

APPLICATION FOR AIR CONSTRUCTION PERMIT

Prepared for:

OLEANDER POWER PROJECT, L.P.
Cocoa, Florida

Prepared by:

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

ECT No. 051331-0100

April 2006

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Oleander Power Project, L.P., plans to install one additional simple-cycle combustion turbine generator (CTG) at its existing Oleander Power Project (OPP) facility located in Brevard County, Florida. The OPP is located at 555 Townsend Road, Cocoa, Florida.

The existing OPP facility consists of four, dual-fuel, nominal 190-megawatt (MW) General Electric (GE) Frame 7FA simple-cycle CTGs, designated as Emissions Units (EU) 001 through 004 and two fuel oil storage tanks, 1.8-million-gallon capacity each, designated as EU 006 and 007. The simple-cycle CTGs are fired primarily with low-sulfur natural gas and use distillate fuel oil as a backup. The original Prevention of Significant Deterioration (PSD) permit, No. 0090180-001-AC, PSD-FL-258, authorized the construction of five "F" Class simple-cycle CTGs and two fuel oil storage tanks. However, only four simple-cycle CTGs and two fuel oil storage tanks were constructed and currently operate under Title V Operation permit No. 0090180-002-AV, with an effective date of January 1, 2004.

OPP is planning to construct and operate one additional simple-cycle GE Frame 7FA. The OPP simple-cycle CTG project will consist of one nominal 190-MW simple-cycle CTG, designated as Unit 5 (EU 005) and fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a backup fuel source. Unit 5 CTG will be equipped with an evaporative cooler, which will be used during baseload operations during periods of high ambient temperatures. The new simple-cycle CTG will operate under the same operating parameters as the existing four simple-cycle CTGs (i.e., a maximum of 3,390 hours per year [hr/yr] at baseload), which includes a maximum of 1,000 hr/yr while firing distillate fuel oil. OPP also plans to install a new 900,000-gallon distillate fuel oil tank. This new fuel oil tank is exempt from permitting since it is not subject to any applicable requirements and its potential emissions are below the Generic Emission Unit Exemption thresholds as specified in Rule 62-210.300(3)(b)(1), Florida Administrative Code (F.A.C.).

Since operation of the proposed project will result in airborne emissions, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), F.A.C. This report, including the required permit application forms and supporting documentation included in the attachments, constitutes OPP'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.

OPP Unit 5 (EU 005) will be located in an attainment area and will have nitrogen oxides (NO_x), particulate matter (PM), particulate matter equal to or less than 10 micrometers (PM_{10}), and sulfur dioxide (SO_2) emissions increases in excess of the 40-, 25-, 15-, and 40-tons-per-year (tpy) thresholds, respectively. Consequently, the addition of OPP Unit 5 qualifies as a major modification to an existing major facility and is subject to the PSD new source review (NSR) requirements of Rule 62-212.400, F.A.C., for NO_x, PM, PM_{10}, and SO_2. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 lists the references used in preparing 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.

1.2 SUMMARY

The OPP simple-cycle CTG project will consist of one nominal 190-MW GE PG7241 (FA) CTG. The CTG will be fired with pipeline-quality natural gas containing no more than 1.0 grain of total sulfur per one hundred standard cubic feet (gr S/100 scf) of natural gas. Low sulfur (containing no more than 0.05 weight percent sulfur [wt%S]) will serve as a backup fuel source.

The planned construction start date for OPP Unit 5 is November 2006. The planned initial date of commencement of operation is December 2007.

Annual emissions have been calculated based on the worst-case annual operating scenario (i.e., 2,390 hr/yr burning natural gas and 1,000 hr/yr burning distillate fuel oil at 59 degrees Fahrenheit [°F]). Based on this calculation, OPP Unit 5 will have the potential to emit 243.1 tpy of NO_x, 83.7 tpy of CO, 38.5 tpy of PM/PM_{10}, 58.9 tpy of SO_2, and 12.9 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, OPP Unit 5 will potentially emit 4.5 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of heavy metals and organic compounds associated with distillate fuel oil combustion. Based on these annual emission rate potentials, NO_x, PM/PM_{10}, and SO_2 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}. OPP Unit 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.

- BACT for SO_2 will be achieved through the use of low-sulfur, pipeline-quality natural gas containing no more than 1.0 gr S/100 scf and distillate fuel oil containing no more than 0.05 wt%S.
- DLN burner technology is proposed as BACT for NO_x for OPP Unit 5 during natural gas firing. For all normal operating loads, the NO_x exhaust concentration will not exceed 9.0 part per million by dry volume (ppmvd), corrected to 15-percent oxygen (O_2). This concentration is consistent with prior FDEP BACT determinations for simple-cycle CTGs. Cost effectiveness of a selective catalytic reduction (SCR) control system was determined to be $11,414 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 $15,219 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, water injection will be employed to reduce the NO_x exhaust concentration to 42 ppmvd, corrected to 15-percent O_2.
- OPP Unit 5 is projected to emit NO_x, PM/PM_{10}, and SO_2 in greater than the PSD significant emission rates. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, OPP Unit 5 project qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(244), 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, OPP Unit 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.
- OPP is presently not a major source of hazardous air pollutants (HAPs). The addition of Unit 5 will not change the status of OPP as a non-major HAP source. Accordingly, OPP Unit 5 will not be subject to any maximum achievable control technology (MACT) requirements.
- The nearest PSD Class I area (Chassahowitzka National Wildlife Refuge) is located approximately 175 kilometers (km) west-northwest of the project site. Air quality and visibility impacts on this Class I area were considered to be negligible based on the distance from the project site.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed OPP Unit 5 will be located at the existing OPP facility, which is located in Cocoa, Brevard County, Florida. Figure 2-1 provides a site location map.

The proposed project consists of the addition of one simple-cycle GE PG7241 (FA) CTG, one 900,000-gallon distillate fuel oil storage tank and ancillary equipment. The simple-cycle CTG will be capable of producing a nominal 190 MW of electricity. Therefore, the OPP overall total nominal generation capacity will increase from 760 MW for the existing four CTGs to 950 MW. The CTG will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a backup fuel source.

OPP Unit 5 will operate up to a maximum of 3,390 hr/yr for natural gas firing, of which, the CTG can operate up to 1,000 hr/yr for oil firing. Since all hourly emissions are higher for the oil firing case, annual emissions have been conservatively estimated based on operating 2,390 hr/yr for natural gas firing and 1,000 hr/yr for oil firing at International Standards Organization (ISO) conditions.

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 OPP major process equipment and structures and the location of the proposed new Unit 5 CTG and 900,000 gallon fuel oil tank.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed OPP Unit 5 will consist of one nominal 190-MW simple-cycle CTG. Figure 2-3 presents a process flow diagram of the simple-cycle CTG.

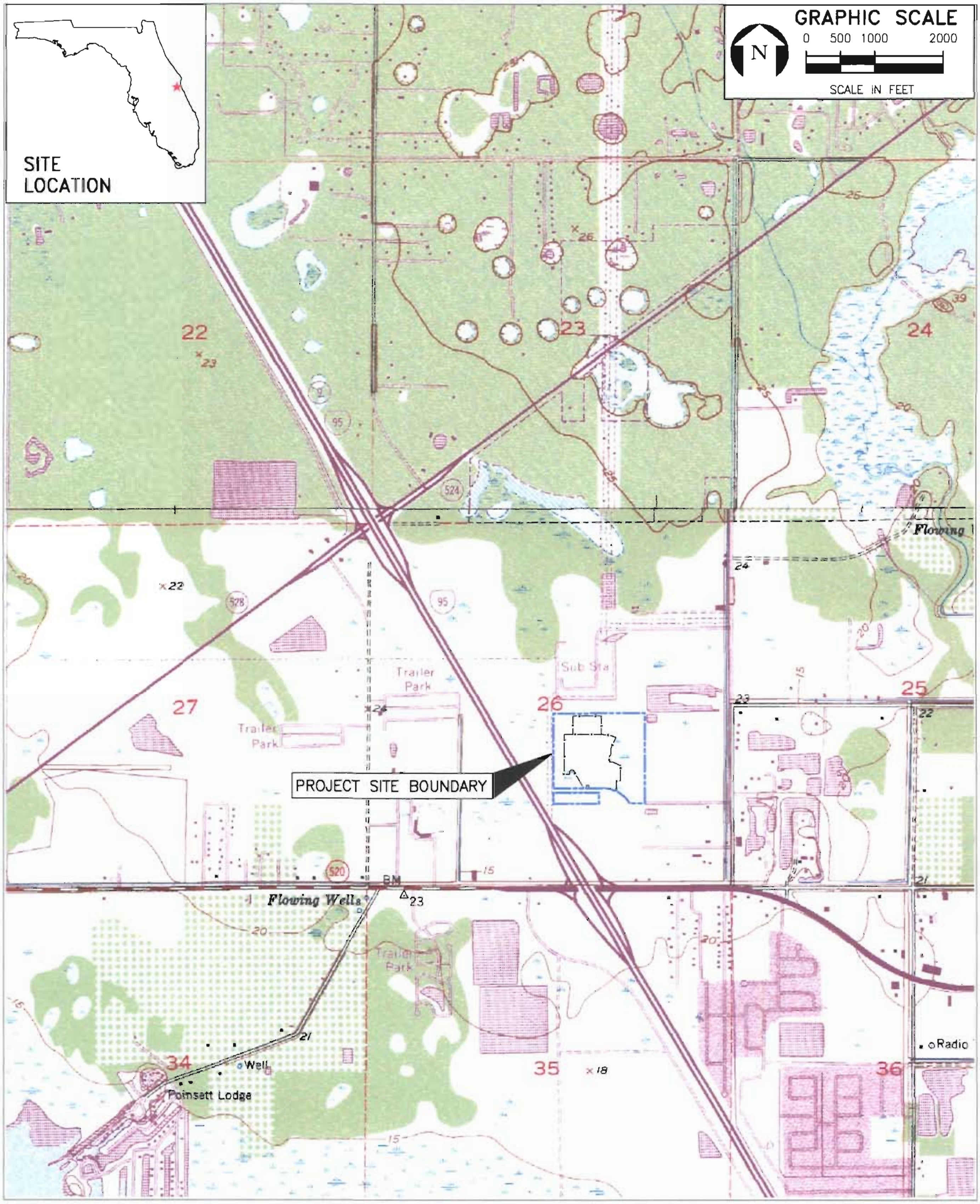

FIGURE 2-1.

SITE LOCATION MAP

OLEANDER POWER PROJECT, COCOA, FLORIDA

Sources: USGS Quads: Lake Poinsett, FL, 1992; Sharpes, Fl, 1992; ECT, 2006.

ECT

Environmental Consulting & Technology, Inc.

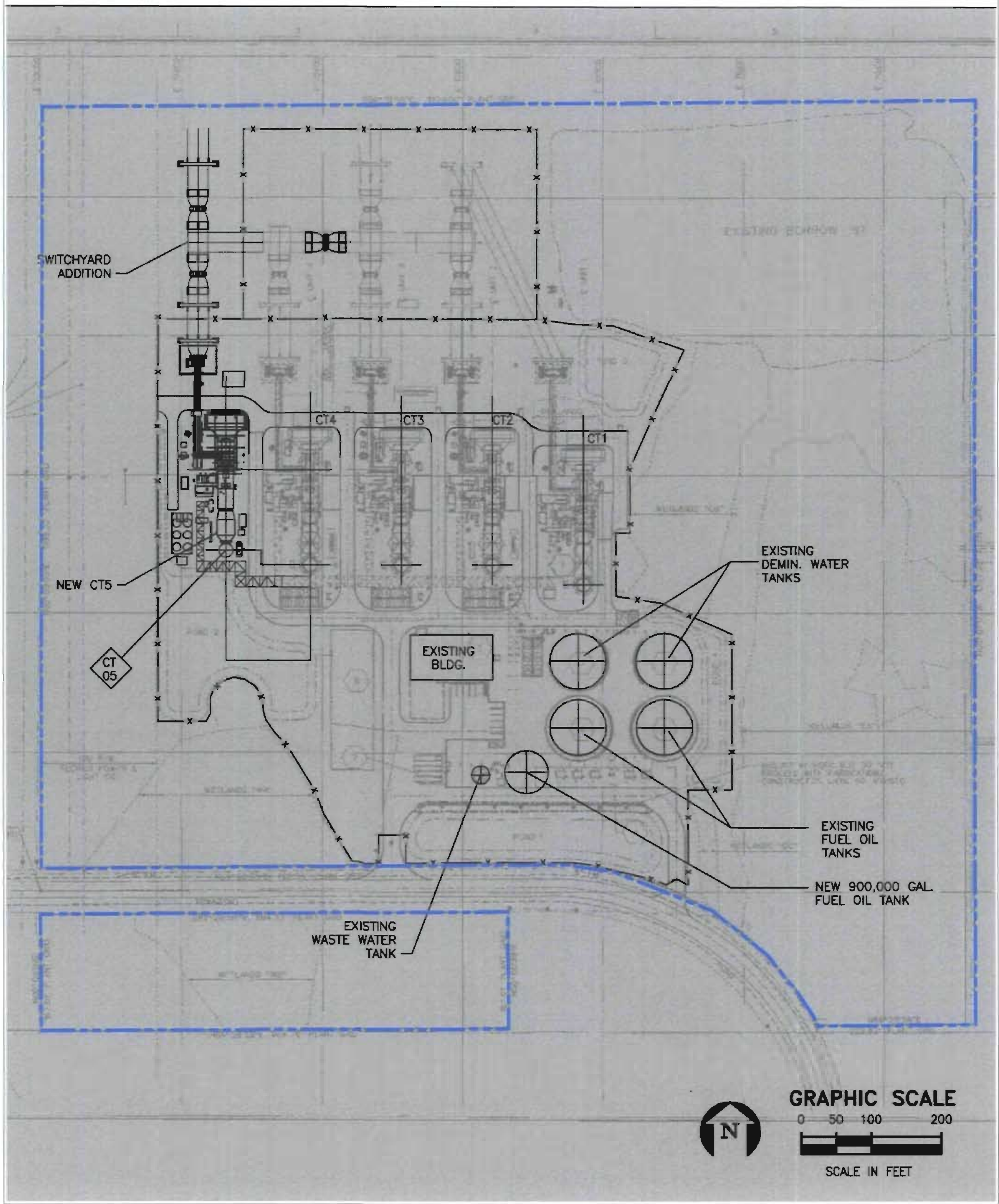

FIGURE 2-2.

OLEANDER POWER PROJECT PLOT PLAN

Source: Southern Company Services, Inc., 2006; ECT, 2006.

ECT

Environmental Consulting & Technology, Inc.

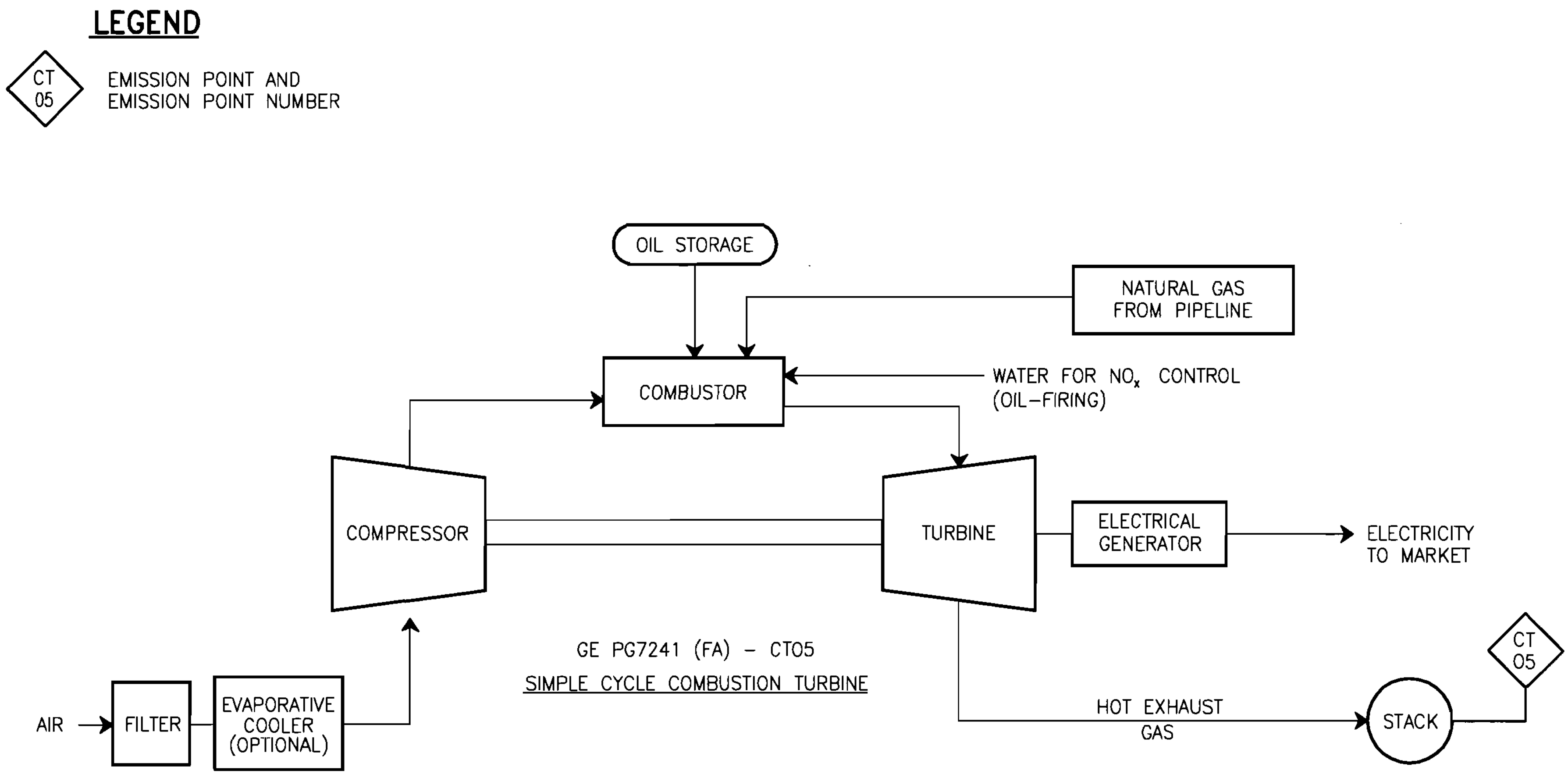

FIGURE 2-3.

SIMPLE CYCLE COMBUSTION TURBINE: PROCESS FLOW DIAGRAM

Source: ECT, 2006.

Environmental Consulting & Technology, Inc.

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.

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 EMISSIONS AND STACK PARAMETERS

All emissions and stack parameters have been based on GE provided data and have been adjusted to reflect anticipated future performance improvements. Specifically, heat input ratings include a margin of 6 percent and 3 percent for natural gas and fuel oil, respectively.

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. HAP emissions consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of distillate fuel oil.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures —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	32	18.0	2.27	5.2	0.66	65.9	8.31	43.9	5.53	6.3	0.79	Neg.	Neg.
	59	18.0	2.27	4.9	0.62	62.5	7.87	41.5	5.23	5.9	0.75	Neg.	Neg.
	95	18.0	2.27	4.5	0.57	56.8	7.16	37.6	4.73	5.4	0.68	Neg.	Neg.
	95 w/ evap. cooling	18.0	2.27	4.7	0.59	59.5	7.50	38.7	4.88	5.5	0.70	Neg.	Neg.
75	32	18.0	2.27	4.2	0.53	52.8	6.65	34.7	4.38	5.0	0.63	Neg.	Neg.
	59	18.0	2.27	4.0	0.51	50.4	6.35	33.4	4.21	4.8	0.60	Neg.	Neg.
	95	18.0	2.27	3.7	0.47	46.6	5.87	31.2	3.93	4.5	0.56	Neg.	Neg.
50	32	18.0	2.27	3.4	0.42	41.8	5.27	28.6	3.60	4.1	0.51	Neg.	Neg.
	59	18.0	2.27	3.2	0.41	40.0	5.04	27.7	3.49	4.0	0.50	Neg.	Neg.
	95	18.0	2.27	3.0	0.37	36.8	4.64	26.3	3.31	3.8	0.47	Neg.	Neg.

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

*Excludes H_2SO_4 mist.

Sources: GE, 2006.
ECT, 2006.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Temperatures—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	32	34.0	4.28	110.8	13.96	351.6	44.30	72.0	9.07	12.3	1.55	Neg.	Neg.
	59	34.0	4.28	106.0	13.36	336.8	42.44	68.1	8.58	11.7	1.47	Neg.	Neg.
	95	34.0	4.28	96.1	12.11	305.3	38.47	61.4	7.74	10.5	1.33	Neg.	Neg.
	95 w/ evap. cooling	34.0	4.28	99.6	12.55	316.4	39.86	63.4	7.99	10.9	1.37	Neg.	Neg.
75	32	34.0	4.28	88.8	11.18	279.3	35.19	55.7	7.02	9.5	1.20	Neg.	Neg.
	59	34.0	4.28	85.7	10.80	269.6	33.97	54.2	6.83	9.3	1.17	Neg.	Neg.
	95	34.0	4.28	78.8	9.92	247.9	31.24	50.7	6.39	8.7	1.09	Neg.	Neg.
50	32	34.0	4.28	70.0	8.82	218.0	27.47	45.8	5.77	7.9	0.99	Neg.	Neg.
	59	34.0	4.28	67.6	8.52	210.5	26.52	44.7	5.63	7.7	0.97	Neg.	Neg.
	95	34.0	4.28	62.0	7.82	193.1	24.33	42.9	5.40	7.3	0.93	Neg.	Neg.

Note: Neg. = negligible

*Excludes H_2SO_4 mist.

Sources: GE, 2006.
ECT, 2006.

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

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	32	0.4	0.05	8.5	1.07
	59	0.4	0.05	8.1	1.02
	95	0.3	0.04	7.4	0.93
	95*	0.4	0.05	7.6	0.96
75	32	0.3	0.04	6.8	0.86
	59	0.3	0.04	6.6	0.83
	95	0.3	0.04	6.0	0.76
50	32	0.3	0.03	5.4	0.68
	59	0.2	0.03	5.2	0.65
	95	0.2	0.03	4.7	0.60

*With evaporative cooling.

Sources: GE, 2006.
ECT, 2006.

Table 2-4. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures—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	32	7.82E-05	9.85E-06	7.27E-03	9.16E-04	1.16E-03	1.47E-04	2.18E-03	2.75E-04	5.82E-03	7.33E-04	3.98E-01	5.01E-02
	59	7.40E-05	9.33E-06	6.89E-03	8.68E-04	1.10E-03	1.39E-04	2.07E-03	2.60E-04	5.51E-03	6.94E-04	3.77E-01	4.75E-02
	95	6.73E-05	8.48E-06	6.26E-03	7.89E-04	1.00E-03	1.26E-04	1.88E-03	2.37E-04	5.01E-03	6.31E-04	3.42E-01	4.31E-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	32	2.36E-04	2.98E-05	4.00E-04	5.04E-05	5.27E-03	6.64E-04	2.36E-02	2.98E-03	1.16E-02	1.47E-03
	59	2.24E-04	2.82E-05	3.79E-04	4.77E-05	4.99E-03	6.29E-04	2.24E-02	2.82E-03	1.10E-02	1.39E-03
	95	2.03E-04	2.56E-05	3.44E-04	4.34E-05	4.54E-03	5.72E-04	2.03E-02	2.56E-03	1.00E-02	1.26E-03

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

Source: ECT, 2006.

Table 2-5. Maximum HAP Emission Rates for 100-Percent Load and Three Temperatures—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	32	3.21E-02	4.04E-03	2.21E-02	2.78E-03	1.10E-01	1.39E-02	6.22E-04	7.83E-05	9.62E-03	1.21E-03	2.21E-02	2.78E-03
	59	3.07E-02	3.87E-03	2.11E-02	2.66E-03	1.06E-01	1.33E-02	5.95E-04	7.50E-05	9.21E-03	1.16E-03	2.11E-02	2.66E-03
	95	2.78E-02	3.51E-03	1.91E-02	2.41E-03	9.57E-02	1.21E-02	5.39E-04	6.80E-05	8.35E-03	1.05E-03	1.91E-02	2.41E-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	32	4.63E-01	5.83E-02	2.81E-02	3.54E-03	1.58E+00	2.00E-01	2.41E-03	3.03E-04	7.02E-02	8.84E-03	9.22E-03	1.16E-03
	59	4.43E-01	5.58E-02	2.69E-02	3.39E-03	1.52E+00	1.91E-01	2.30E-03	2.90E-04	6.72E-02	8.46E-03	8.83E-03	1.11E-03
	95	4.01E-01	5.06E-02	2.44E-02	3.07E-03	1.37E+00	1.73E-01	2.09E-03	2.63E-04	6.09E-02	7.67E-03	8.00E-03	1.01E-03

		PAH		Selenium	
		lb/hr	g/s	lb/hr	g/s
100	32	8.02E-02	1.01E-02	5.01E-02	6.32E-03
	59	7.68E-02	9.67E-03	4.80E-02	6.05E-03
	95	6.96E-02	8.77E-03	4.35E-02	5.48E-03

Note: Neg. = negligible

Source: ECT, 2006.

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., 32°F), baseload, and fuel oil firing.

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 2,390 hr/yr (natural gas firing), baseload operation for 1,000 hr/yr (fuel oil firing), and an ambient temperature of 59°F.

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

Table 2-6. Maximum Annualized Emission Rates for OPP Unit 5

Pollutant	Annualized Emission Rates OPP Unit 5 (tpy) Natural Gas (based on 2,390 hr/yr)	Distillate Fuel Oil (based on 1,000 hr/yr)	Total
NO_x	74.6	168.4	243.1
CO	49.6	34.0	83.7
PM/PM_{10}*	21.5	17.0	38.5
SO_2	5.9	53.0	58.9
VOC	7.1	5.8	12.9
H_2SO_4	0.5	4.1	4.5
HAPs			
1,3 Butadiene	8.85E-05	1.54E-02	1.54E-02
Acetaldehyde	8.23E-03	N/A	8.23E-03
Acrolein	1.32E-03	N/A	1.32E-03
Arsenic	N/A	1.06E-02	1.06E-02
Benzene	2.47E-03	5.28E-02	5.53E-02
Beryllium	N/A	2.98E-04	2.98E-04
Cadmium	N/A	4.61E-03	4.61E-03
Chromium	N/A	1.06E-02	1.06E-02
Ethylbenzene	6.58E-03	N/A	6.58E-03
Formaldehyde	4.50E-01	2.21E-01	6.72E-01
Lead	3.54E-02	1.34E-02	4.89E-02
Manganese	N/A	7.58E-01	7.58E-01
Mercury	N/A	1.15E-03	1.15E-03
Naphthalene	2.67E-04	3.36E-02	3.39E-02
Nickel	N/A	4.41E-03	4.41E-03
PAH	4.53E-04	3.84E-02	3.88E-02
Propylene oxide	5.97E-03	N/A	5.97E-03
Selenium	N/A	2.40E-02	2.40E-02
Toluene	2.67E-02	N/A	2.67E-02
Xylenes	1.32E-02	N/A	1.32E-02
Total HAPs	0.55	1.19	1.74

*Excludes H_2SO_4 mist.

Sources: OPP, 2006.
GE, 2006.
ECT, 2006.

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	32	60.0	18.29	1,085	858	116.8	35.6	22.0	6.71
	59	60.0	18.29	1,111	873	112.9	34.4	22.0	6.71
	95	60.0	18.29	1,149	894	106.3	32.4	22.0	6.71
	95*	60.0	18.29	1,135	886	109.3	33.3	22.0	6.71
75	32	60.0	18.29	1,134	885	95.4	29.1	22.0	6.71
	59	60.0	18.29	1,154	896	93.4	28.5	22.0	6.71
	95	60.0	18.29	1,184	913	90.0	27.4	22.0	6.71
50	32	60.0	18.29	1,185	914	80.9	24.6	22.0	6.71
	59	60.0	18.29	1,200	922	79.3	24.2	22.0	6.71
	95	60.0	18.29	1,200	922	76.3	23.3	22.0	6.71

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

*With evaporative cooling.

Sources: GE, 2006.
ECT, 2006.

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	32	60.0	18.29	1,064	846	117.2	35.7	22.0	6.71
	59	60.0	18.29	1,095	864	113.7	34.7	22.0	6.71
	95	60.0	18.29	1,138	888	106.6	32.5	22.0	6.71
	95*	60.0	18.29	1,122	879	109.4	33.3	22.0	6.71
75	32	60.0	18.29	1,134	885	94.7	28.9	22.0	6.71
	59	60.0	18.29	1,152	895	93.5	28.5	22.0	6.71
	95	60.0	18.29	1,183	913	89.9	27.4	22.0	6.71
50	32	60.0	18.29	1,185	914	79.6	24.3	22.0	6.71
	59	60.0	18.29	1,200	922	78.6	24.0	22.0	6.71
	95	60.0	18.29	1,200	922	75.9	23.1	22.0	6.71

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

*With evaporative cooling.

Sources: GE, 2006.
ECT, 2006.

3.0 AIR QUALITY STANDARDS AND NSR APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (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. OPP is located in Brevard County, which is presently designated in 40 CFR 81.310 as better than national standards (for SO_2, total suspended particulates [TSPs] 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 [$PM_{2.5}$]), and not designated (for lead). Brevard 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

Since Brevard County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants, OPP Unit 5 is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The existing OPP 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.

The proposed new OPP Unit 5 simple-cycle CTG will have potential emissions in excess of the significant emission rate thresholds. Therefore, the project qualifies as a major

Table 3-1. National and Florida Quality Standards (micrograms per cubic meter [μg/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 μg/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 μg/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.

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, PM, PM_{10}, and SO_2 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 B provides detailed emission rate estimates for OPP Unit 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	243.1	40	Yes
CO	83.7	100	No
PM	38.5	25	Yes
PM_{10}	38.5	15	Yes
SO_2	58.9	40	Yes
Ozone/VOC	12.9	40	No
Lead	0.049	0.6	No
Mercury	0.0012	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	4.5	7	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

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2006.

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 OPP Unit 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 FDEP, 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

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

Source: Section 62-212.400, Table 212.400-3, F.A.C.
ECT, 2006.

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.
ECT, 2006.

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

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

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, 6th 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, PM/PM_{10}, and SO_2 for OPP Unit 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 (carbon monoxide [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, stationary combustion turbines, with a heat input at peak load equal to or greater than 10 MMBtu/hr, that commenced construction, modification, or reconstruction after February 18, 2005, will be subject to NSPS Subpart KKKK. Stationary combustion turbines subject to NSPS Subpart KKKK will not be subject to NSPS Subpart GG. Therefore, OPP Unit 5 will be subject to the requirements of NSPS Subpart KKKK.

The final rule establishes NO_x emission standards for new combustion turbines with a heat input at peak load greater than 850 MMBtu/hr of 15 ppm at 15-percent O_2 or 0.43 pounds per megawatt-hour (lb/MWhr) for natural gas-firing and 42 ppm at 15-percent O_2 or 1.3 lb/MWhr for firing fuels other than natural gas. The final rule

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
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
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Emission Fee Credit	$25 per ton
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × total capital investment

Source: EPA, 2002.
ECT, 2006.

establishes an SO_2 emission standard of 0.90 lb/MWhr (gross output) or, alternatively, an SO_2 emission standard of 0.060 lb/MMBtu (heat input).

OPP Unit 5 NO_x emissions of 9 ppmvd and 42 ppmvd at 15-percent O_2 for natural gas and distillate fuel oil firing respectively demonstrate compliance with the NO_x emission requirements of NSPS Subpart KKKK. Table B-8 demonstrates compliance with the SO_2 emission requirements of NSPS Subpart KKKK.

The proposed OPP Unit 5 has 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 single-cycle combustion turbines (SCCTs). Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAP, respectively, by reference. As noted previously, NSPS Subpart KKKK, Stationary Gas Turbines, is applicable to OPP Unit 5. There are no applicable NESHAP requirements.

Tables 5-2 and 5-3 summarize applicable federal and state emission standards, respectively.

BACT emission limitations proposed for OPP Unit 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.

Table 5-2. Federal Emission Limitations

NSPS Subpart KKKK, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x (>850 MMBtu/hr)	
Natural gas	15 ppmvd at 15-percent O_2 or 0.43 lb/MWhr
Fuels other than natural gas	42 ppmvd at 15-percent O_2 or 1.3 lb/MWhr
SO_2	0.90 lb/MWhr or 0.06 lb/MMBtu heat input

Source: 40 CFR 60, Subpart KKKK.
ECT, 2006.

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.
ECT, 2006.

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. OPP Unit 5 will be fired with natural gas as the primary fuel and distillate fuel oil as the backup 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 OPP Unit 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. OPP Unit 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. OPP Unit 5 will be fired primarily with pipeline-quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a backup 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 OPP Unit 5.

5.4 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 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 ammonium (NH). Prompt NO_x comprises a small portion of total NO_x in conventional

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

Emission Source	Proposed PM/PM_{10} BACT
GE PG7241 (FA)	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: OPP, 2006.
ECT, 2006.

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.

5.4.1 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.

DLN 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 O_2.

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.

The proposed OPP Unit 5 is a GE 7FA unit. 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 OPP Unit 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 O_2) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

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

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O \tag{3}$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \tag{4}$$

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:

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

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 O_2-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:

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

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:

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

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:

$$CO + \tfrac{1}{2}\,O_2 \rightarrow CO_2 \qquad (11)$$

$$SO_2 + \tfrac{1}{2}\,O_2 \rightarrow SO_3 \qquad (12)$$

$$SO_3 + \text{SORBER} \rightarrow [SO_3 + \text{SORBER}] \qquad (13)$$

$$[SO_3 + \text{SORBER}] + 4\,H_2 \rightarrow H_2S + 3\,H_2O + [\text{SORBER}] \qquad (14)$$

(below 500°F)

$$[SO_3 + \text{SORBER}] + H_2 \rightarrow SO_2 + H_2O + [\text{SORBER}] \qquad (15)$$

(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 OPP Unit 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 OPP Unit 5 exhaust gas stream (approximately 1,100°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent O_2) environment. Due to high excess air rates, the O_2 content of the OPP Unit 5 exhaust 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 OPP Unit 5 exhaust gas stream. In addition, EMx™ control technology has not been commercially demonstrated on a large CT. The OPP Unit 5, GE PG7241 (7FA) unit, has a nominal generation capacity of 175 MW. Accordingly, OPP Unit 5 is 7 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 OPP Unit 5 was confined to advanced DLN combustors (for gas-firing), wet injection (for oil-firing), 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 require exhaust gas cooling prior to treatment. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.4.2 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 OPP Unit 5 due to the pressure drop across the catalyst bed. Additional energy would be needed for introducing dilution air into the exhaust gas stream in order to reduce the gas temperature, pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for OPP Unit 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 5,339,250 kwh (18,218 MMBtu) per year at baseload (175-MW) operation. This energy penalty is equivalent to the use of 17.35 million ft^3 of natural gas annually based on a natural gas heating value of 1,050 Btu/ft^3. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $160,200 per year. Actual generation cost based on current fuel prices is $0.150/kwh resulting in an energy penalty of $800,900.

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 45.4 tpy (at baseload and 59°F ambient temperature) for a SCR design NH_3 slip rate of 10 ppmvd. However, NH_3 slip can increase significantly during start-ups, upsets, or failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of NH_3 is 20 ppmv, releases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases.
- 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.

5.4.3 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 9.0 and 42.0 ppmvd at 15-percent O_2 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 O_2 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 cost factors provided in Table 5-5. Emission reductions were calculated assuming baseload operation for 2,390 and 1,000 hr/yr for gas- and oil-firing, respectively, at an annual average ambient temperature of 59°F. Tables 5-6 and 5-7 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to OPP Unit 5 was determined to be $11,414 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 $15,219 per ton of NO_x removed. These control costs are considered economically unreasonable. Table 5-8 summarizes results of the NO_x BACT analysis.

Table 5-5. Economic Cost Factors

Factor	Units	Value
Interest rate	Percent	7.0*
SCR system life	Years	15
SCR catalyst life	Years	3
SCR catalyst control efficiency (gas)	Percent	61.1
SCR catalyst control efficiency (oil)	Percent	76.2
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: OPP, 2006.
ECT, 2006.

Table 5-6. Capital Costs for SCR System, OPP Unit 5

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	4,065,000	A
Sales tax	243,900	0.06 × A
Instrumentation	406,500	0.10 × A
Freight	203,300	0.05 × A
Subtotal Purchased Equipment	**4,918,700**	**B**
Installation		
Foundations and supports	393,500	0.08 × B
Handling and erection	688,600	0.14 × B
Electrical	196,700	0.04 × B
Piping	98,400	0.02 × B
Insulation for ductwork	49,200	0.01 × B
Painting	49,200	0.01 × B
Subtotal Installation Cost	**1,475,600**	
Total Direct Costs (TDC)	**6,394,300**	
Indirect Costs		
Engineering	491,900	0.10 × B
Construction and field expenses	245,900	0.05 × B
Contractor fees	491,900	0.10 × B
Startup	98,400	0.02 × B
Performance test	49,200	0.01 × B
Contingency	147,600	0.03 × B
Total Indirect Costs (TIC)	**1,524,900**	
TOTAL CAPITAL INVESTMENT (TCI)	**7,919,200**	TDC + TIC

Source: ECT, 2006.

Table 5-7. Annual Operating Costs for SCR System, OPP Unit 5

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Labor and material costs		
Operator	4,700	A
Supervisor	700	0.15 × A
Maintenance		
Labor	4,700	B
Materials	4,700	1.0 × B
Subtotal Labor, Material, and Maintenance Costs	**14,800**	**C**
Catalyst costs		
Replacement (materials and labor)	2,147,100	3-year replacement
Annualized Catalyst Costs	**818,200**	
Electricity	5,300	
Aqueous Ammonia	16,100	
Energy Penalties		
Turbine backpressure	160,200	0.9% penalty
Total Direct Costs (TDC)	**1,014,600**	
<u>Indirect Costs</u>		
Overhead	8,900	0.60 × C
Administrative charges	158,400	0.02 × TCI
Property taxes	79,200	0.01 × TCI
Insurance	79,200	0.01 × TCI
Capital recovery	649,500	15 years @ 7.0%
Permit Fee Credit	(4,300)	$25/ton
Total Indirect Costs (TIC)	**970,900**	
TOTAL ANNUAL COST (TAC)	**1,985,500**	TDC + TIC

Sources: ECT, 2006.

Table 5-8. Summary of NO_x BACT Analysis

Control Option	Emission Impacts: Emission Rates lb/hr	Emission Impacts: Emission Rates tpy	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Environmental Impact (Y/N)
SCR	24.3 (NG) 80.2 (FO)	69.1	174.0	7,919,200	1,985,500	11,414	18,218	Y	Y
Baseline	62.5 (NG) 336.8 (FO)	243.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7241 (FA) SCCT, 100-percent load, 59°F ambient temperature, 2,390 hr/yr gas-fired, 1,000 hr/yr fuel oil-fired, FDEP economic factors.

Sources: GE, 2006.
ECT, 2006.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

At baseload operation, maximum NO_x exhaust concentrations from OPP Unit 5 will be 9.0 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 OPP Unit 5 are consistent with prior recent FDEP BACT determinations for SCCTs.

Table 5-9 summarizes the NO_x BACT emission limits proposed for OPP Unit 5.

5.5 BACT ANALYSIS FOR SO_2

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

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

Fuel Treatment

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

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.

Table 5-9. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits	
	ppmvd*	lb/hr†
GE PG 7241 (FA) SCCT (Natural Gas firing)	9.0	62.5
GE PG 7241 (FA) SCCT (Distillate Fuel Oil firing)	42.0	336.8

*Corrected to 15-percent O_2, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: OPP, 2006.
ECT, 2006.

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. OPP Unit 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.

Pipeline-quality natural gas contains a negligible amount of sulfur; typically less than 0.50 grains per standard cubic foot (gr/scf) (equivalent to 0.0016 wt%S and 16 parts per million by weight [ppmw]). Ultra-low sulfur diesel fuel (ULSD) containing no more than 0.0015 wt%S (15 ppmw) 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 OPP Unit 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 wt%S (500 ppmw) 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.

5.5.2 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 OPP Unit 5 economic analysis, an average price differential of 5.4 cents was used. Based on 1,000-hr/yr operation of distillate fuel oil firing, annual distillate fuel oil consumption is 14,507,000 gallons per year. The increase in distillate fuel oil costs in using ULSD, based on the EIA data, is $783,378 per year. The reduction in SO_2 emissions is 51.4 tpy for OPP Unit 5 resulting in a cost effectiveness of $15,241 per ton of SO_2 reduced. Details of the SO_2 economic analysis are provided in Table 5-10.

5.5.3 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 controls are not applicable, use of low sulfur fuel is considered to represent BACT for OPP Unit 5. Natural gas utilized for OPP Unit 5 will be pipeline-quality and distillate fuel oil used for the backup fuel source will contain no more than 0.05 wt%S. Table 5-11 summarizes the SO_2 BACT emission limits proposed for OPP Unit 5.

5.6 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-12 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-13 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-10. SO_2 Economic Analysis for ULSD

Data

Number of simple-cycle CTs:	1	
Hourly fuel oil usage:	14,507	gal/hr (Case 4, 100% load, 59°F)
	106,049	lb/hr (Case 4, 100% load, 59°F)
Annual fuel oil hours:	1,000	hr/yr
Fuel oil cost premium:	0.054	$/gal (ULSD vs. 0.05 % S)

Calculations

Annual fuel oil usage:	14,507,000	gal/yr (Case 4, 100% load, 59°F)
	106,049,000	lb/yr (Case 4, 100% load, 59°F)
Cost differential:	783,378	$/yr

Fuel type	Sulfur (wt%)	SO_2 (ton/yr)	SO_2 ($/ton)
Distillate fuel oil (base case)	0.05	53.0	—
Distillate fuel oil (ULSD)	0.0015	1.6	15,241

Sources: EIA/DOE, 2001.
GE, 2006.
OPP, 2006.
ECT, 2006.

Table 5-11. 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: OPP, 2006.
ECT, 2006.

Table 5-12. Summary of BACT Control Technologies

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

Source: OPP, 2006.
ECT, 2006.

Table 5-13. Summary of Proposed BACT Emission Limits

Emission Source/Pollutant	Proposed BACT Emission Limits ppmvd*	lb/hr†
GE PG7241 (FA) SCCT (natural gas firing)		
PM/PM_{10}	10-percent opacity	
NO_x	9.0	62.5
SO_2	(fuel ≤1.0 gr S/100 scf)	
GE PG7241 (FA) SCCT (distillate fuel firing)		
PM/PM_{10}	10-percent opacity	
NO_x	42.0	336.8
SO_2	(fuel ≤0.05 wt % S)	

*Corrected to 15-percent O_2, 24-hour block average.
†CT compressor inlet air temperature of 59°F, baseload.

Sources: OPP, 2006.
ECT, 2006.

6.0 AIR QUALITY IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

The approach to assessing air quality impacts for a new or modified emission source generally begins by determining the impacts of only the proposed facility. If the impacts of the proposed facility are below specified PSD significance impact levels (SILs), then no further analysis is required. If the impacts of the proposed facility are found to exceed a particular PSD SIL, further analysis considering other existing sources and background pollutant concentrations is required for that SIL.

The approach used to analyze the potential impacts of OPP Unit 5, as described in detail in the following subsections, was developed in accordance with this accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed. The air quality analysis for Oleander Power Project Unit 5 project was conducted in accordance with FDEP's approval of the general methodology, meteorological data, and receptor grids.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, OPP Unit 5 will have the potential to emit 243.1 tpy of NO_x, 83.7 tpy of CO, 38.5 tpy of PM/PM_{10}, 58.9 tpy of SO_2, 12.9 tpy of VOCs, and 4.5 tpy of H_2SO_4 mist. As shown previously in Table 3-2, potential emissions of NO_x, SO_2, PM, and PM_{10} are each projected to exceed the applicable PSD significant emission rate (SER) threshold. Potential emissions from OPP Unit 5 will be below the applicable PSD SER levels for all other PSD regulated pollutants. Accordingly, OPP Unit 5 is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for NO_x, PM, PM_{10}, and SO_2.

6.3 MODEL SELECTION AND USE

Air quality models are applied at two levels: screening and refined. At the screening level, models provide conservative estimates of impacts to determine whether more detailed modeling is required. Screening modeling can also be used to identify the worst-case operating scenario for an emissions unit such as a combustion turbine that operates under various operating conditions. Once the worst-case operating scenario is identified by screening modeling, maximum impacts can be determined using refined modeling for the worst-case scenario. The current version of EPA's SCREEN3 Dispersion Model (Version 96043; February 12, 1996) was employed as a screening tool to determine the worst-case operating scenario for OPP Unit 5.

The refined modeling consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides more accurate estimates of source impacts. The American Meteorological Society (AMS)/EPA Regulatory Model (AERMOD) modeling system, together with 5 years of hourly meteorological data from the National Oceanographic and Atmospheric Administration (NOAA) National Climatic Data Center (NCDC) were used in the refined ambient impact analysis. AERMOD was used to obtain refined impact predictions for both short- and long-term periods.

6.3.1 SCREENING MODEL TECHNIQUES

OPP Unit 5 will operate under a variety of operating scenarios. These scenarios include two different fuels (natural gas and distillate fuel oil), different loads and ambient air temperatures, and the optional use of inlet air evaporative cooling. Plume dispersion and, therefore, ground-level impacts, will be affected by these different operating scenarios since pollutant emission rates, exhaust gas temperatures, and exhaust gas velocities will change. Tables B-2 and B-3 in Appendix B provide the natural gas and distillate fuel oil operating cases, respectively. Since the hourly emissions of NO_x, SO_x, and PM_{10} are greater for all operating cases for distillate fuel oil firing, only the ten operating cases for distillate fuel oil firing were evaluated for the air quality impact analysis.

The SCREEN3 dispersion model was used to evaluate each OPP Unit 5 operating scenario firing distillate fuel oil for each pollutant of concern. The objective was to identify the scenario that caused the highest impacts and then conduct refined modeling for that specific scenario. The SCREEN3 model implements screening methods contained in EPA's *Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised*. SCREEN3 is a simple model that calculates 1-hour average concentrations over a range of predefined worst-case meteorological conditions. The SCREEN3 model includes algorithms to assess building wake downwash effects and for analyzing concentrations in both simple and complex terrain.

A nominal emission rate of 10.0 grams per second (g/s) was used for all SCREEN3 model runs. The SCREEN3 model results were then adjusted to reflect the maximum emission rate for each operating scenario (i.e., model results were multiplied by the ratio of maximum emission rates [in g/s] to 10.0 g/s). Summaries of the screening modeling results showing, for each Unit 5 operating scenario and pollutant evaluated, the SCREEN3 unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted SCREEN3 1-hour average maximum impact are provided in Section 7.3.

However, after review of the SCREEN3 model results, a clear worst-case scenario could not be identified. Therefore, refined modeling analysis was performed for all ten operating scenarios while firing distillate fuel oil for all 5 years of meteorological data. This conservative approach ensures that the worst-case scenario would be evaluated.

6.3.2 REFINED MODEL TECHNIQUES

Regulatory agency recommended procedures for conducting air quality impact assessments are contained in EPA's Guideline on Air Quality Models (GAQM). The GAQM is codified in Appendix W of 40 CFR 51. In the November 9, 2005, Federal Register, EPA approved use of AERMOD as a GAQM Appendix A preferred model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model. The latest version of AERMOD (Version 04300) was used to assess OPP Unit 5 project air quality impacts at receptor locations within 15 km of the project site.

6.4 MODEL OPTIONS

Procedures applicable to the AERMOD modeling system specified in the latest version of the User's Guide for the AMS/EPA Regulatory Model—AERMOD (September 2004) and EPA's November 9, 2005, revisions to the GAQM were followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. By selecting DFAULT option, AERMOD assumes flat terrain. The CONC option specifies the calculation of concentrations. Oleander Power Project is located in a rural section of Brevard County. AERMOD options regarding pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected.

As previously mentioned, the AERMOD modeling system was used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword.

6.5 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.

6.6 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 exceeding the height of the stack being modeled.

Site elevation for the Oleander Power Project is approximately 27.5 feet above mean sea level (ft-msl). Consistent with ambient air impact analyses performed in support of the original PSD permit application, flat terrain was assumed for Oleander Power Project.

6.7 BUILDING WAKE EFFECTS

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

$$Hg = H + 1.5\ L$$

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

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

The height proposed for the OPP Unit 5 stack (i.e., 60 ft above grade level) will be less than the *de minimis* GEP height of 65 meters (213 ft). Since the stack height of OPP Unit 5 stack will comply with the EPA promulgated final stack height regulations (40 CFR 51), actual project stack heights were used in the modeling analyses.

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. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the OPP Unit 5 ambient impact analysis, the complex downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for

PRIME (BPIPPRM) (Version 04274; September 30, 2004). The EPA BPIP program was used to determine the area of influence for each CT structure, aboveground storage tank and building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10° to 360°) building heights (BUILDHGT keyword), lengths (BUILDLEN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD. Dimensions of the building/structures evaluated for the wake effects were determined from existing building dimensions, engineering layouts, and specifications and are shown in Table 6-1. The buildings are shown in three-dimension in Figure 6-1.

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."

The entire Oleander Power Project property boundary is not fenced. The fenced portion of Oleander Power Project is shown in Figure 2-2 and therefore, the nearest locations of general public access are at these fence lines.

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

- Fence line receptors—Receptors placed on the site fence line spaced 50 meters apart.
- Near-Field Cartesian Receptors—Receptors between the center of the site and extending out to approximately 3 km at 100-meter spacings.
- Mid-Field Cartesian Receptors—Receptors between 3 km and extending to approximately 6 km at 250-meter spacings.
- Far-Field Cartesian Receptors—Receptors between 6 km and extending to approximately 15 km at 500-meter spacings.

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
CT Units 1-5 inlet filter (Tier 3)	15.8	10.0	16.6
CT Units 1-5 inlet duct (Tier 2)	7.6	16.0	13.9
CT Units 1-5 enclosure/silencer (Tier 1)	7.6	31.3	7.7
Two existing demineralizer water storage tanks	—	24.4*	15.2
Two existing fuel oil storage tanks	—	24.4*	15.2
One new fuel oil storage tank	—	18.9*	15.2
Existing control/administrative building	19.8	36.0	6.1

*Diameter.

Sources: OPP, 2006.
ECT, 2006.

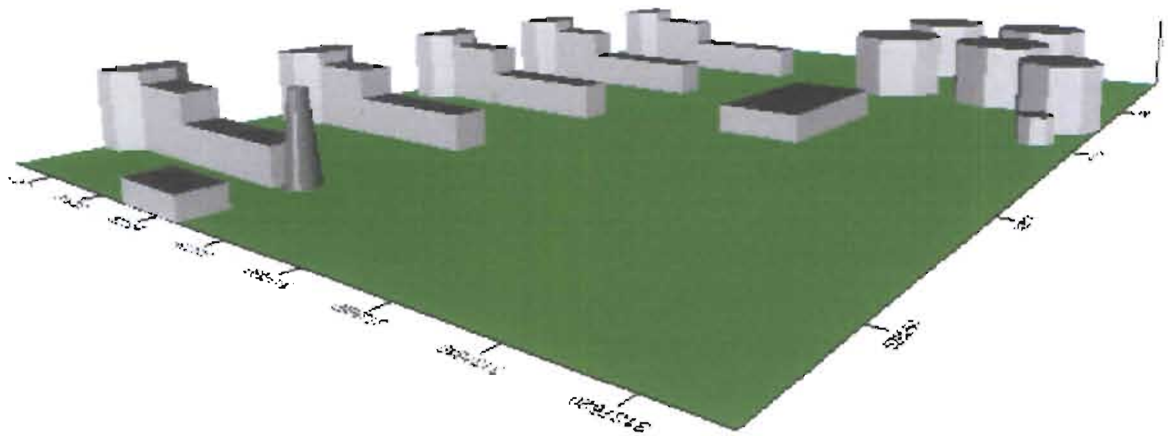

FIGURE 6-1.
BUILDINGS USED IN THE DOWNWASH ANALYSIS
OLEANDER POWER PROJECT UNIT 5
Source: ECT, 2006.

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Figure 6-2 provides a graphical representation of the fenceline receptors. Figure 6-3 provides a graphical representation of the near-field receptor grids (out to a distance of 3 km). Figure 6-4 provides a graphical representation of the far-field receptor grids (from 3 km out to a distance of 15 km).

6.9 METEOROLOGICAL DATA

The AERMOD meteorological preprocessor AERMET (Version 04300) was used to process surface meteorological data collected at the Orlando International Airport (OIA) (Weather Bureau, Air Force and Navy [WBAN] Station No. 92801) and upper air data from Tampa Bay/Ruskin (WBAN Station No. 12842). These two meteorological stations are consistent with the stations used in the ambient impact analysis performed in support of the original PSD permit application. Raw surface and upper air data, however, was obtained for the most recent 5-year period, 1996 to 2000, from NCDC. Missing surface and upper air data (i.e., data gaps) were filled in accordance with EPA guidance.

In accordance with FDEP guidance, area characteristics in the vicinity of the OIA meteorological station were used in determining the boundary layer parameter estimates. Obstacles to the wind flow, amount of moisture at the surface, and reflectivity of the surface all affect the boundary layer parameter estimates. The AERMET keywords FREQ_SECT, SECTOR, and SITE_CHAR are used to define the surface albedo, Bowen ratio, and surface roughness length (z_0).

The albedo is the fraction of total incident solar radiation reflected by the surface back to space without absorption. The daytime Bowen ratio is an indicator of surface moisture and is used for determining planetary boundary layer parameters for convective conditions. The surface roughness length is related to the height of obstacles to the wind flow and represents the height at which the mean horizontal windspeed is zero.

A 3 km radius area around the OIA meteorological station was divided into 12 equal radial segments of 30 degrees each. The land use was determined for each segment based on aerial maps. Guidance contained in the AERMET User's Guide (Tables 4-1 through 4-3), in conjunction with vicinity aerial maps, were used to define the values of surface

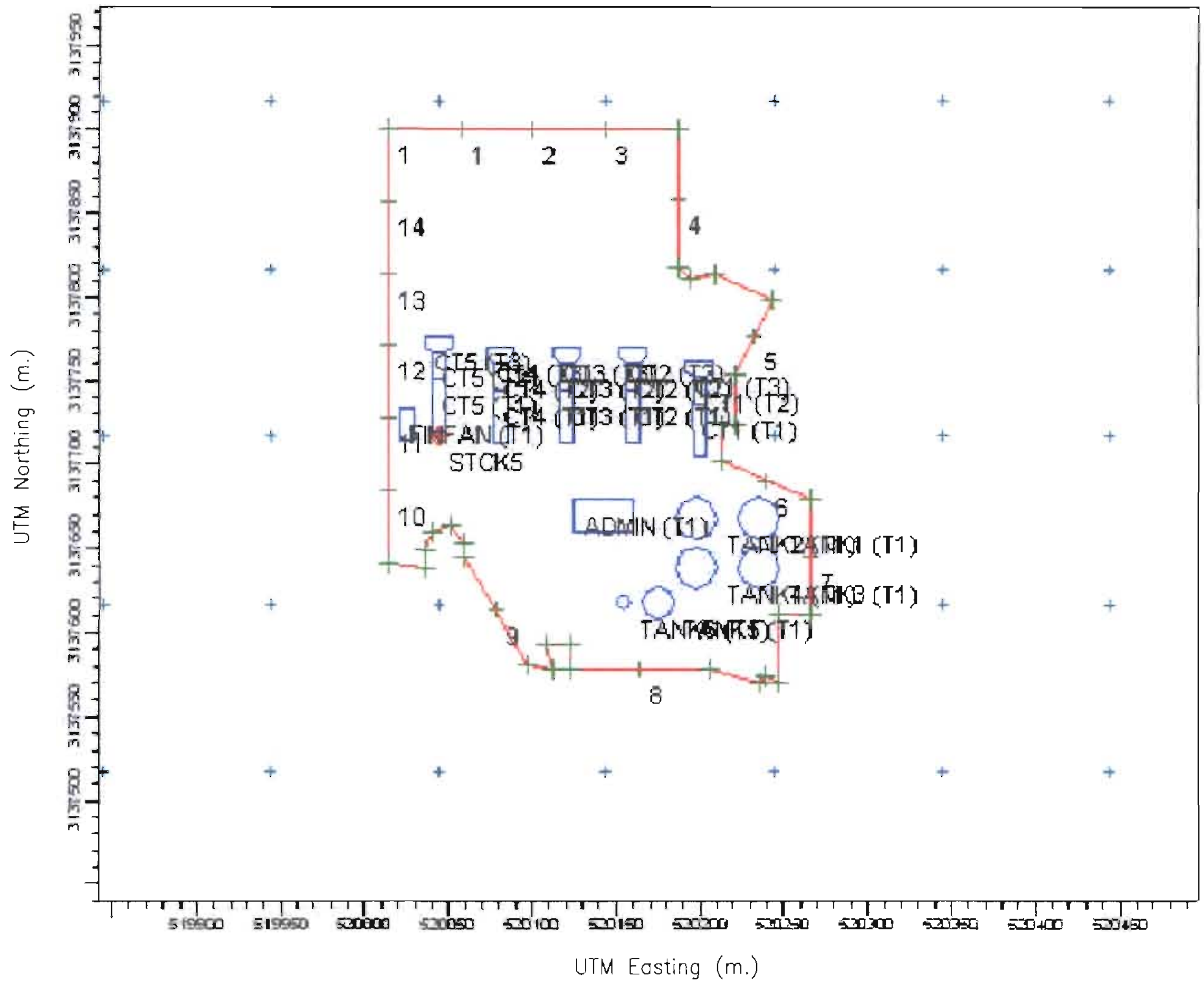

FIGURE 6-2.

FENCELINE RECEPTORS

OLEANDER POWER PROJECT UNIT 5

Source: ECT, 2006.

ECT

Environmental Consulting & Technology, Inc.

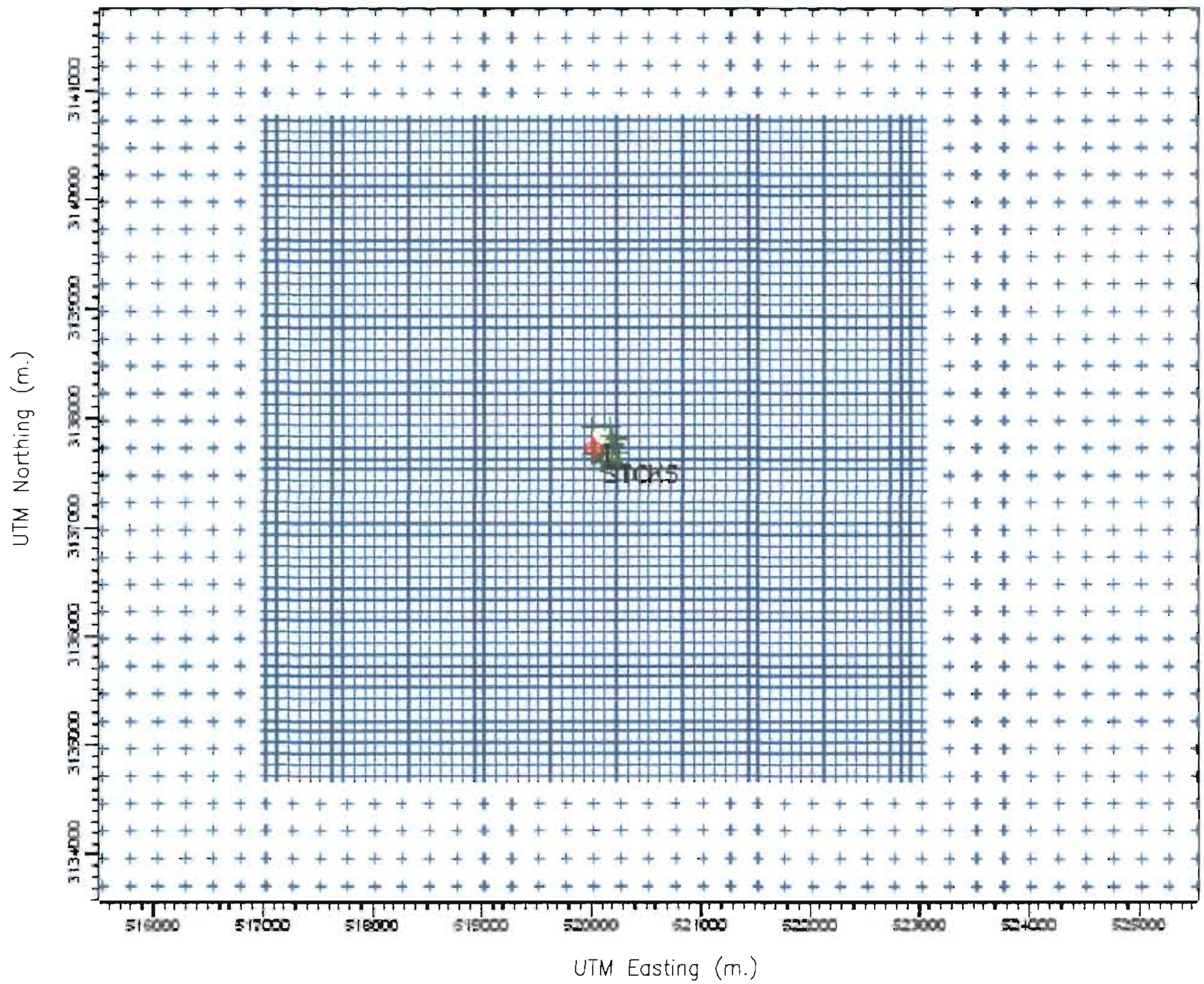

FIGURE 6-3.

NEAR-FIELD RECEPTORS

OLEANDER POWER PROJECT UNIT 5

Source: ECT, 2006.

Environmental Consulting & Technology, Inc.

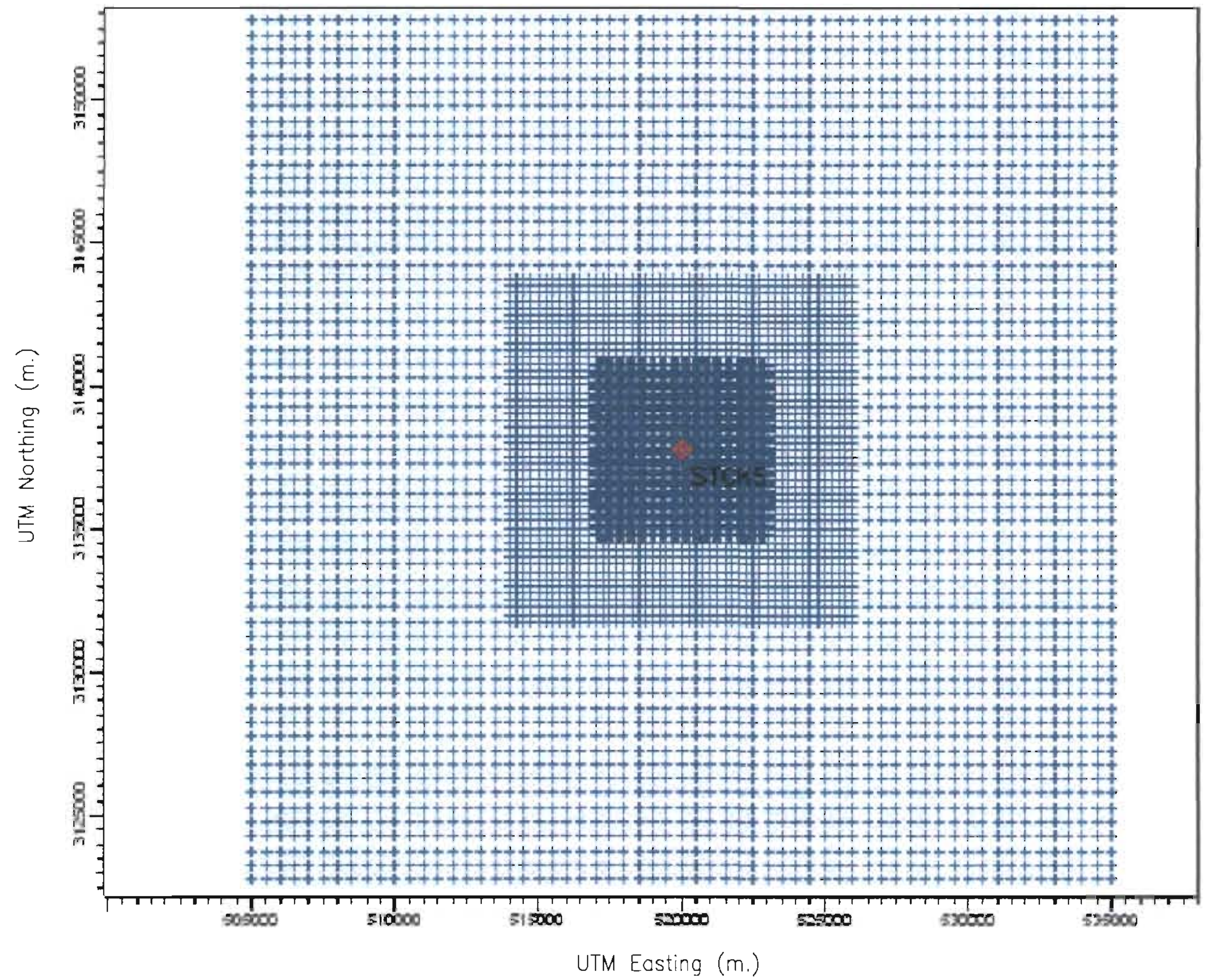

FIGURE 6-4.
FAR-FIELD RECEPTORS
OLEANDER POWER PROJECT UNIT 5
Source: ECT, 2006.

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albedo, daytime Bowen ratio, and surface roughness length for OPP Unit 5 air quality impact assessment. Table 6-2 provides a summary of the AERMET surface characteristics for the OIA meteorological station.

AERMET creates two files that are used by AERMOD (i.e., surface and profile files). The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature. AERMET was utilized in accordance with the latest version (February 2005) of the User's Guide for the AERMOD Meteorological Preprocessor (AERMET) and EPA's November 9, 2005, revisions to the GAQM.

6.10 MODELED EMISSION INVENTORY

Modeled on-property emission sources consist of the proposed OPP Unit 5 only. As will be discussed in Section 7.0, emissions from OPP Unit 5 resulted in maximum air quality impacts below the PSD significant impact levels for all PSD pollutants. Therefore, a full, multi-source interactive ambient air quality analyses was not required.

Table 6-2. AERMET Surface Characteristics for OIA

			Percent Land Use							
Sector	Beginning Angle (°)	End Angle (°)	Annual Grassland (%)	Annual Deciduous Forest (%)	Annual Desert Shrubland (%)	Annual Urban (%)	Annual Low Density Residential* (%)	Average Annual Albedo	Annual Bowen Ratio	Annual Surface Roughness
1	0	30	75.0	-	-	-	25.0	0.277	0.873	0.192
2	30	60	50.0	25.0	-	25.0	-	0.251	0.969	0.495
3	60	90	75.0	-	-	25.0	-	0.269	0.963	0.280
4	90	120	75.0	-	25.0	-	-	0.299	1.650	0.096
5	120	150	50.0	50.0	-	-	-	0.253	0.838	0.470
6	150	180	50.0	50.0	-	-	-	0.253	0.838	0.470
7	180	210	50.0	50.0	-	-	-	0.253	0.838	0.470
8	210	240	37.5	-	37.5	25.0	-	0.283	2.200	0.364
9	240	270	25.0	25.0	25.0	25.0	-	0.260	1.794	0.551
10	270	300	-	25.0	-	25.0	50.0	0.224	1.064	0.798
11	300	330	-	50.0	-	25.0	25.0	0.219	1.023	0.862
12	330	360	75.0	-	-	25.0	-	0.269	0.963	0.280

Note: - = not applicable.

*Defined by Alabama Department of Environmental Management (ADEM): 1/3 urban, 1/3 grassland, 1/3 deciduous forest.

Sources: EPA, 2004, 2005.
ECT, 2006.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive screening and refined modeling was conducted to assess the air quality impacts resulting from OPP Unit 5 operations. This section provides the results of the air quality analysis.

7.2 CONCLUSIONS

Comprehensive dispersion modeling using the EPA SCREEN3 (screening) and AERMOD (refined) dispersion models demonstrates that operation of OPP Unit 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 multi-source interactive assessment of air quality impacts with respect to the AAQS and PSD Class II increments was not required.

7.3 SCREENING MODELING RESULTS

As previously described in Section 6.0, the EPA SCREEN3 dispersion model was used in an attempt to assess the worst case for OPP Unit 5 operating cases while burning distillate fuel oil. The worst-case scenario would then be used in the refined modeling. As shown in Tables 7-1, 7-2, and 7-3, the results of the SCREEN3 modeling did not provide a definitive worst-case scenario. Therefore, refined modeling using AERMOD was used to evaluate all ten cases while burning distillate fuel oil.

7.4 REFINED MODELING RESULTS

The refined EPA AERMOD modeling system, using 5 years (1996 through 2000) of hour-by-hour meteorology and comprehensive receptor grids, was employed for all ten operating cases for distillate fuel oil firing.

Table 7-1. SCREEN3 Model Results - NO2 Impacts--OPP Unit 5 CT

	Operating Scenarios				1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Natural Gas Firing								
1-NG	100	32	8.31	N	1.34	0.831	1.11	1,780
2-NG	75	32	6.65	N	24.48	0.665	16.28	50
3-NG	50	32	5.27	N	86.77	0.527	45.73	50
4-NG	100	59	7.87	N	1.45	0.787	1.14	1,754
5-NG	75	59	6.35	N	27.70	0.635	17.59	50
6-NG	50	59	5.04	N	91.97	0.504	46.35	50
7-NG	100	95	7.16	N	2.7	0.716	1.94	66
8-NG	100	95	7.5	Y	1.5	0.750	1.15	1,725
9-NG	75	95	5.87	N	35.2	0.587	20.68	50
10-NG	50	95	4.64	N	104.1	0.464	48.30	50
B. Distillate Fuel Oil Firing								
1-FO	100	32	44.300	N	1.38	4.4300	6.131	1,778
2-FO	75	32	35.190	N	26.20	3.5190	92.198	50
3-FO	50	32	27.470	N	94.61	2.7470	259.894	50
4-FO	100	59	42.440	N	1.45	4.2440	6.133	1,755
5-FO	75	59	33.970	N	27.02	3.3970	91.787	50
6-FO	50	59	26.520	N	96.02	2.6520	254.645	50
7-FO	100	95	38.470	N	2.4	3.8470	9.040	67
8-FO	100	95	39.860	Y	1.5	3.9860	6.134	1,723
9-FO	75	95	31.240	N	35.2	3.1240	110.059	50
10-FO	50	95	24.330	N	108.6	2.4330	264.224	50

Source: ECT, 2006

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Table 7-2. SCREEN3 Model Results - SO_2 Impacts--OPP Unit 5 CT

Operating Scenarios					1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Natural Gas Firing								
1-NG	100	32	0.66	N	1.34	0.066	0.09	1,780
2-NG	75	32	0.53	N	24.48	0.053	1.30	50
3-NG	50	32	0.42	N	86.77	0.042	3.64	50
4-NG	100	59	0.62	N	1.45	0.062	0.09	1,754
5-NG	75	59	0.51	N	27.70	0.051	1.41	50
6-NG	50	59	0.41	N	91.97	0.041	3.77	50
7-NG	100	95	0.57	N	2.7	0.057	0.15	66
8-NG	100	95	0.59	Y	1.5	0.059	0.09	1,725
9-NG	75	95	0.47	N	35.2	0.047	1.66	50
10-NG	50	95	0.37	N	104.1	0.037	3.85	50
B. Distillate Fuel Oil Firing								
1-FO	100	32	13.960	N	1.38	1.3960	1.932	1,778
2-FO	75	32	11.180	N	26.20	1.1180	29.292	50
3-FO	50	32	8.820	N	94.61	0.8820	83.446	50
4-FO	100	59	12.200	N	1.45	1.2200	1.763	1,755
5-FO	75	59	9.800	N	27.02	0.9800	26.480	50
6-FO	50	59	7.800	N	96.02	0.7800	74.896	50
7-FO	100	95	11.000	N	2.4	1.1000	2.585	67
8-FO	100	95	11.400	Y	1.5	1.1400	1.754	1,723
9-FO	75	95	9.000	N	35.2	0.9000	31.707	50
10-FO	50	95	7.100	N	108.6	0.7100	77.106	50

Source: ECT, 2006

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Table 7-3. SCREEN3 Model Results - PM10 Impacts--OPP Unit 5 CT

Operating Scenarios					1-Hour Impacts			
Case No.	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Evaporative Cooling (Y/N)	SCREEN3 Unadjusted 10 g/s Results (ug/m^3)	Emission Rate Factor (g/s)	SCREEN3 Adjusted Results (ug/m^3)	Downwind Distance (m)
A. Natural Gas Firing								
1-NG	100	32	2.27	N	1.34	0.227	0.30	1,780
2-NG	75	32	2.27	N	24.48	0.227	5.56	50
3-NG	50	32	2.27	N	86.77	0.227	19.70	50
4-NG	100	59	2.27	N	1.45	0.227	0.33	1,754
5-NG	75	59	2.27	N	27.70	0.227	6.29	50
6-NG	50	59	2.27	N	91.97	0.227	20.88	50
7-NG	100	95	2.27	N	2.7	0.227	0.61	66
8-NG	100	95	2.27	Y	1.5	0.227	0.35	1,725
9-NG	75	95	2.27	N	35.2	0.227	8.00	50
10-NG	50	95	2.27	N	104.1	0.227	23.63	50
B. Distillate Fuel Oil Firing								
1-FO	100	32	4.280	N	1.38	0.4280	0.592	1,778
2-FO	75	32	4.280	N	26.20	0.4280	11.214	50
3-FO	50	32	4.280	N	94.61	0.4280	40.493	50
4-FO	100	59	4.280	N	1.45	0.4280	0.618	1,755
5-FO	75	59	4.280	N	27.02	0.4280	11.565	50
6-FO	50	59	4.280	N	96.02	0.4280	41.097	50
7-FO	100	95	4.280	N	2.4	0.4280	1.006	67
8-FO	100	95	4.280	Y	1.5	0.4280	0.659	1,723
9-FO	75	95	4.280	N	35.2	0.4280	15.078	50
10-FO	50	95	4.280	N	108.6	0.4280	46.481	50

Source: ECT, 2006

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Detailed OPP Unit 5 AERMOD results for each year of meteorology are summarized in Tables 7-4, 7-5, and 7-6. These tables provide maximum OPP Unit 5 impacts, the locations of these maximum impacts, and relevant regulatory criteria. Please note that the receptor locations for all maximum impacts are located within 1 km of the OPP Unit 5 stack. Since receptor spacing was 100 meters out to a distance of 3 km, receptor spacing of 100 meters was employed within all areas of maximum impacts.

Maximum OPP Unit 5 air quality impacts using AERMOD and the identified worst-case operating cases are summarized in Table 7-7. The AERMOD results presented in Table 7-7 demonstrates that OPP Unit 5 air quality impacts, for all pollutants and averaging periods, will be below the PSD significant impact levels previously shown in Table 3-4.

Table 7-4. Air Quality Impact Analysis Summary, OPP Unit 5 — Distillate Fuel Oil Firing

	Case 1 (100% Load, 32°F Ambient)					Case 2 (75% Load, 32°F Ambient)					Case 3 (50% Load, 32°F Ambient)				
	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000
Nominal 10 g/s Impacts:															
High, 1-Hour ($\mu g/m^3$)	9.36	6.72	5.97	8.07	6.71	12.01	8.75	7.71	10.16	9.00	14.77	11.02	9.83	12.74	13.74
High, 3-Hour ($\mu g/m^3$)	5.69	4.06	3.76	2.88	2.66	7.60	5.37	4.94	3.79	3.53	9.46	6.90	6.10	4.84	4.91
High, 8-Hour ($\mu g/m^3$)	2.54	2.14	2.24	2.20	1.71	3.29	2.91	2.97	2.75	2.12	4.23	3.73	3.80	3.32	2.55
High, 24-Hour ($\mu g/m^3$)	1.08	0.87	1.31	0.82	0.80	1.44	1.17	1.78	1.04	0.98	1.82	1.49	2.31	1.27	1.16
Annual ($\mu g/m^3$)	0.074	0.077	0.084	0.087	0.074	0.092	0.096	0.107	0.108	0.093	0.110	0.115	0.131	0.128	0.112
SO_2															
Emission Rate (g/s)	13.96	13.96	13.96	13.96	13.96	11.18	11.18	11.18	11.18	11.18	8.82	8.82	8.82	8.82	8.82
High, 3-Hour ($\mu g/m^3$)	7.95	5.66	5.25	4.03	3.72	**8.50**	6.01	5.53	4.23	3.95	8.34	6.08	5.38	4.27	4.33
High, 24-Hour ($\mu g/m^3$)	1.509	1.212	1.825	1.146	1.112	1.610	1.306	1.988	1.158	1.092	1.609	1.317	**2.036**	1.117	1.025
Annual ($\mu g/m^3$)	0.1037	0.1077	0.1178	**0.1212**	0.1029	0.1026	0.1075	0.1200	0.1204	0.1035	0.0972	0.1018	0.1156	0.1132	0.0988
NO_2															
Emission Rate (g/s)	44.30	44.30	44.30	44.30	44.30	35.19	35.19	35.19	35.19	35.19	27.47	27.47	27.47	27.47	27.47
Tier 2 Annual ($\mu g/m^3$)	0.2468	0.2564	0.2805	**0.2885**	0.2449	0.2421	0.2537	0.2833	0.2842	0.2443	0.2271	0.2378	0.2700	0.2645	0.2307
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 ($\mu g/m^3$)	0.463	0.372	0.560	0.351	0.341	0.616	0.500	0.761	0.443	0.418	0.781	0.639	0.988	0.542	0.498
Annual ($\mu g/m^3$)	0.0318	0.0330	0.0361	0.0372	0.0315	0.0393	0.0411	0.0459	0.0461	0.0396	0.0472	0.0494	0.0561	0.0550	0.0479

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Table 7-5. Air Quality Impact Analysis Summary, OPP Unit 5 — Distillate Fuel Oil Firing

	Case 4 (100% Load, 59°F Ambient)					Case 5 (75% Load, 59°F Ambient)					Case 6 (50% Load, 59°F Ambient)				
	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000
Nominal 10 g/s Impacts:															
High, 1-Hour (μg/m^3)	9.62	6.91	6.12	8.27	6.91	12.13	8.86	7.82	10.26	9.25	15.08	11.14	9.95	12.88	14.16
High, 3-Hour (μg/m^3)	5.85	4.16	3.86	2.97	2.74	7.70	5.45	5.01	3.83	3.58	9.59	6.99	6.17	4.90	5.07
High, 8-Hour (μg/m^3)	2.60	2.21	2.30	2.26	1.74	3.33	2.95	3.02	2.78	2.15	4.29	3.78	3.86	3.35	2.58
High, 24-Hour (μg/m^3)	1.11	0.89	1.35	0.84	0.81	1.46	1.18	1.80	1.05	0.99	1.85	1.51	2.34	1.28	1.17
Annual (μg/m^3)	0.076	0.079	0.087	0.089	0.075	0.093	0.097	0.109	0.109	0.094	0.111	0.117	0.133	0.130	0.113
SO_2															
Emission Rate (g/s)	13.36	13.36	13.36	13.36	13.36	10.80	10.80	10.80	10.80	10.80	8.52	8.52	8.52	8.52	8.52
High, 3-Hour (μg/m^3)	7.81	5.56	5.16	3.96	3.66	8.31	5.89	5.41	4.13	3.87	8.17	5.95	5.25	4.18	4.32
High, 24-Hour (μg/m^3)	1.485	1.192	1.798	1.123	1.086	1.577	1.280	1.948	1.131	1.065	1.577	1.288	1.994	1.091	1.000
Annual (μg/m^3)	0.1014	0.1055	0.1156	0.1185	0.1007	0.1001	0.1049	0.1173	0.1175	0.1011	0.0949	0.0993	0.1129	0.1104	0.0964
NO_2															
Emission Rate (g/s)	42.44	42.44	42.44	42.44	42.44	33.97	33.97	33.97	33.97	33.97	26.52	26.52	26.52	26.52	26.52
Tier 2 Annual (μg/m^3)	0.2415	0.2513	0.2753	0.2824	0.2400	0.2361	0.2475	0.2767	0.2772	0.2384	0.2214	0.2319	0.2636	0.2578	0.2250
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 (μg/m^3)	0.476	0.382	0.576	0.360	0.348	0.625	0.507	0.772	0.448	0.422	0.792	0.647	1.002	0.548	0.503
Annual (μg/m^3)	0.0325	0.0338	0.0370	0.0380	0.0323	0.0397	0.0416	0.0465	0.0466	0.0401	0.0476	0.0499	0.0567	0.0555	0.0484

Table 7-6. Air Quality Impact Analysis Summary, OPP Unit 5 — Distillate Fuel Oil Firing

	Case 7 (100% Load, 95°F Ambient)					Case 8 (100% Load, 95°F Ambient, Evap. Cooling)				
	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000
Nominal 10 g/s Impacts:										
High, 1-Hour (μg/m³)	10.36	7.45	6.55	8.85	7.41	10.09	7.25	6.39	8.64	7.22
High, 3-Hour (μg/m³)	6.32	4.47	4.16	3.21	2.95	6.13	4.35	4.05	3.12	2.87
High, 8-Hour (μg/m³)	2.80	2.41	2.45	2.40	1.85	2.72	2.34	2.39	2.35	1.81
High, 24-Hour (μg/m³)	1.20	0.97	1.46	0.90	0.86	1.17	0.94	1.42	0.88	0.84
Annual (μg/m³)	0.080	0.084	0.093	0.094	0.080	0.079	0.082	0.090	0.092	0.078
SO_2										
Emission Rate (g/s)	12.11	12.11	12.11	12.11	12.11	12.55	12.55	12.55	12.55	12.55
High, 3-Hour (μg/m³)	7.65	5.42	5.04	3.89	3.57	7.69	5.46	5.08	3.92	3.60
High, 24-Hour (μg/m³)	1.455	1.175	1.769	1.088	1.044	1.467	1.180	1.778	1.100	1.059
Annual (μg/m³)	0.0973	0.1017	0.1120	0.1142	0.0973	0.0987	0.1030	0.1132	0.1157	0.0985
NO_2										
Emission Rate (g/s)	38.47	38.47	38.47	38.47	38.47	39.86	39.86	39.86	39.86	39.86
Tier 2 Annual (μg/m³)	0.2319	0.2423	0.2669	0.2721	0.2319	0.2352	0.2454	0.2697	0.2756	0.2346
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
High, 24-Hour (μg/m³)	0.514	0.415	0.625	0.385	0.369	0.500	0.402	0.606	0.375	0.361
Annual (μg/m³)	0.0344	0.0359	0.0396	0.0404	0.0344	0.0337	0.0351	0.0386	0.0395	0.0336

	Case 9 (75% Load, 95°F Ambient)					Case 10 (50% Load, 95°F Ambient)				
	1996	1997	1998	1999	2000	1996	1997	1998	1999	2000
Nominal 10 g/s Impacts:										
High, 1-Hour (μg/m³)	12.58	9.29	8.22	10.76	10.00	**16.26**	11.69	10.46	13.50	15.61
High, 3-Hour (μg/m³)	8.04	5.73	5.23	3.98	3.76	**10.15**	7.36	6.45	5.20	5.63
High, 8-Hour (μg/m³)	3.50	3.09	3.17	2.88	2.23	**4.58**	4.00	4.11	3.50	0.00
High, 24-Hour (μg/m³)	1.53	1.25	1.89	1.09	1.02	1.97	1.60	**2.49**	1.34	1.23
Annual (μg/m³)	0.096	0.101	0.113	0.113	0.097	0.116	0.122	**0.139**	0.135	0.118
SO_2										
Emission Rate (g/s)	9.92	9.92	9.92	9.92	9.92	7.82	7.82	7.82	7.82	7.82
High, 3-Hour (μg/m³)	7.98	5.69	5.19	3.95	3.73	7.94	5.76	5.05	4.07	4.40
High, 24-Hour (μg/m³)	1.517	1.235	1.879	1.081	1.009	1.537	1.248	1.946	1.050	0.959
Annual (μg/m³)	0.0953	0.0998	0.1120	0.1117	0.0964	0.0909	0.0952	0.1087	0.1057	0.0925
NO_2										
Emission Rate (g/s)	31.24	31.24	31.24	31.24	31.24	24.33	24.33	24.33	24.33	24.33
Tier 2 Annual (μg/m³)	0.2250	0.2358	0.2646	0.2638	0.2276	0.2122	0.2222	0.2535	0.2466	0.2159
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
High, 24-Hour (μg/m³)	0.655	0.533	0.811	0.467	0.435	0.841	0.683	**1.065**	0.574	0.525
Annual (μg/m³)	0.0411	0.0431	0.0483	0.0482	0.0416	0.0498	0.0521	**0.0595**	0.0578	0.0506

Maximum Impacts	Project Impact	Receptor Location UTM Coordinates E	N	Distance (km)	Case No.	Year	Class II SIL	% of SIL (%)
SO_2								
High, 3-Hour (μg/m³)	8.50	520544.75	3137415.8	0.58	2	1996	25	33.98
High, 24-Hour (μg/m³)	2.036	520744.75	3137615.8	0.71	3	1998	5	40.71
Annual (μg/m³)	0.1212	519644.75	3137815.8	0.41	1	1999	1	12.12
NO_2								
Annual (μg/m³)	0.2885	519644.75	3137815.8	0.41	1	1999	1	28.85
PM_{10}								
High, 24-Hour (μg/m³)	1.07	520744.75	3137615.8	0.71	10	1998	5	21.30
Annual (μg/m³)	0.0595	520444.75	3137615.8	0.41	10	1998	1	5.95

Source: ECT, 2006.

Table 7-7. Refined (AERMOD) Modeling Results—Maximum Criteria Pollutant Impacts

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Distance to Receptor (km)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.29	0.41	1
PM_{10}	Annual	0.06	0.41	1
	24-hour	1.07	0.71	5
SO_2	Annual	0.12	0.41	1
	24-hour	2.04	0.71	5
	3-hour	8.50	0.58	25

Source: ECT, 2006.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air quality monitoring station is located at Freedom 7 Elementary School on South Fourth Street in Cocoa Beach, Brevard County, approximately 19 km southeast of the Oleander Power Project. This station monitors the ambient air for 1- and 8-hour average ozone. The nearest ambient air quality monitoring station that monitors for PM_{10} and $PM_{2.5}$ is located on North Primrose in Orlando, approximately 58 km northwest of the project site. The nearest NO_2 ambient air quality monitoring station is located at Morris Boulevard in Winter Park, Orange County, approximately 61 km northwest of the project site. The nearest CO ambient air quality monitoring station is located on Orange Avenue in Orlando, approximately 60 km northwest of the project site. The nearest ambient air quality monitoring station for lead is situated in Tampa, Hillsborough County, approximately 162 km southwest of the project site. All of the Orange County ambient air quality monitoring stations are operated by the Orange County Environmental Protection Division (OCEPD). The Hillsborough County site that monitors ambient air for lead is operated by the Hillsborough County Environmental Protection Commission (HCEPC). Summaries of the 2003 and 2004 ambient air quality data for these monitoring stations are provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 3.2, 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 PSD pollutants will be emitted from Unit B 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 3-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from OPP Unit 5.

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}	Orange	Orlando	East Washington	0950004	441,220.0	3,178,650.0	89	297	24-Hr	Jan-Dec	60	34	32		150[1]
									Annual					16.5	50[2]
	Orange	Orlando	595 North Primrose	0951004	466,200.0	3,158,100.0	58	291	24-Hr	Jan-Dec	61	56	47		150[1]
									Annual					19.9	50[2]
	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	24-Hr	Jan-Dec	61	30	28		150[1]
									Annual					17.6	50[2]
SO_2	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,647	44.5	44.5		
									3-Hr			31.4	28.8		1,300[3]
									24-Hr			15.7	10.5		365[3]
									Annual					3.4	80[2]
NO_2	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,437	122.3	122.3		100[2]
									Annual					20.3	
CO	Orange	Orlando	No. 1 Orange Avenue	0951005	462,960.0	3,157,100.0	60	289	1-Hr	Jan-Dec	8,551	3,910.0	3,680.0		40,000[3]
									8-Hr			2,300.0	2,300.0		10,000[3]
	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,667	2,990.0	2,645.0		40,000[3]
									8-Hr			1,750.0	1,750.0		10,000[3]
O_3	Brevard	Melbourne	401 Florida Avenue	0090007	536,510.0	3,103,060.0	38	154	1-Hr	Mar-Oct	225	188.5			235[4]
									8-Hr	Mar-Oct	221	164.9			
	Brevard	Cocoa Beach	400 South Fourth Street	0094001	537,700.0	3,131,500.0	19	109	1-Hr	Mar-Oct	240	176.7			235[4]
									8-Hr	Mar-Oct	240	155.1			
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	162	254	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, 2006.
FDEP, 2006.

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/m³): 1st High	2nd High	Arithmetic Mean	Standard
PM_{10}	Orange	Orlando	East Washington	0950004	441,220.0	3,178,650.0	89	297	24-Hr	Jan-Dec	56	26	25		150[1]
									Annual					16.9	50[2]
	Orange	Orlando	595 North Primrose	0951004	466,200.0	3,158,100.0	58	291	24-Hr	Jan-Dec	58	41	36		150[1]
									Annual					19.3	50[2]
	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	24-Hr	Jan-Dec	57	41	29		150[1]
									Annual					18.1	50[2]
SO_2	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,324	47.1	41.9		
									3-Hr			36.7	23.6		1,300[3]
									24-Hr			13.1	13.1		365[3]
									Annual					3.4	80[2]
NO_2	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,418	105.4	99.7		100[2]
									Annual					17.9	
CO	Orange	Orlando	No. 1 Orange Avenue	0951005	462,960.0	3,157,100.0	60	289	1-Hr	Jan-Dec	8,596	4,715.0	3,105.0		40,000[3]
									8-Hr			2,185.0	2,070.0		10,000[3]
	Orange	Winter Park	Morris Boulevard	0952002	464,515.0	3,163,490.0	61	295	1-Hr	Jan-Dec	8,460	2,760.0	2,760.0		40,000[3]
									8-Hr			1,840.0	1,840.0		10,000[3]
O_3	Brevard	Melbourne	401 Florida Avenue	0090007	536,510.0	3,103,060.0	38	154	1-Hr	Mar-Oct	216	153.1			235[4]
									8-Hr	Mar-Oct	210	141.3			
	Brevard	Cocoa Beach	400 South Fourth Street	0094001	537,700.0	3,131,500.0	19	109	1-Hr	Mar-Oct	222	153.1			235[4]
									8-Hr	Mar-Oct	218	139.4			
Lead	Hillsborough	Tampa	Gulf Coast Lead	0571066	364,000.0	3,093,400.0	162	254	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, 2006.
FDEP, 2006.

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The results of these analyses were presented in detail in Section 7.0. The following paragraphs summarize the dispersion modeling results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM10

The maximum 24-hour PM_{10} impact was predicted to be 1.07 $\mu g/m^3$. This concentration is below the 10 $\mu g/m^3$ *de minimis* level ambient impact level. 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 2.04 $\mu g/m^3$. 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 0.29 $\mu g/m^3$. 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.

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

9.1.1 PROJECT GROWTH IMPACTS

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 OPP Unit 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.

OPP Unit 5 is 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, Unit B is not projected to generate any new employment positions at Oleander Power Project and therefore, will not adversely affect growth in the area. The increase in natural gas demand due to the operation of OPP Unit 5 will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.1.2 AREA GROWTH SINCE 1977

U.S. Census Bureau data shows that the population of the Orlando metropolitan area has roughly doubled between 1980 and 2000. The Orlando area population, as of April 2003, was 1,755,000. The rate of population growth in the area declined from 2000 to 2003, reflecting the effect of the economic slowdown beginning in early 2001 and very slow growth during most of 2002.

The Orlando area is home to several major theme parks, including Walt Disney World and Universal Studios, and is a major tourist destination. In addition, numerous business conventions and meetings are held in the Orlando area. A local study attributed one-quarter of all its visitors to business, including meetings and conventions.

As a tourism-dominated region, there is little major industrial activity in the Orlando region. The major air quality impact of the growth that has occurred in the Orlando area is predominantly due to an increase in mobile source activity. However, the reductions in mobile source tailpipe emissions and improvements in fuel quality since the late 1970s resulted in improvements in the area's air quality. Although the Orlando area was once classified as an ozone nonattainment area, it is presently classified as attainment for all criteria pollutants.

Accordingly, it is concluded that air quality in the Orlando area has not deteriorated since 1977. As discussed in Section 7.0, the relatively minor emissions associated with OPP Unit 5 will result in insignificant air quality impacts.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the Oleander Power Project due to Unit 5 operations will be below the applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the Oleander Power Project are anticipated.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for OPP Unit 5. Visible emissions from the exhaust stack, the primary Unit 5 emission source, will be 10 percent opacity or less, excluding water. Emissions of primary particulates and sulfur oxides from OPP Unit 5 will be low due to the exclusive use of pipeline quality natural gas and low sulfur distillate fuel oil. OPP Unit 5 will comply with all applicable FDEP requirements pertaining to visible emissions.

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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 any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also 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 • Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL). **Air Operation Permit** – Use this form to apply for: • An initial federally enforceable state air operation permit (FESOP); or • An initial/revised/renewal Title V air operation permit. **Air Construction Permit & 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: **Oleander Power Project, L.P.**	
2. Site Name: **Oleander Power Project**	
3. Facility Identification Number: **0090180**	
4. Facility Location... Street Address or Other Locator: **555 Townsend Road** City: **Cocoa** County: **Brevard** Zip Code: **32926**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Allison Little**
2. Application Contact Mailing Address... Organization/Firm: **Gulf Power Company** Street Address: **One Energy Place** City: **Pensacola** State: **Florida** Zip Code: **32520-0328**
3. Application Contact Telephone Numbers... Telephone: **(850) 444 - 6537** ext. **Fax: (850) 444 - 6217**
4. Application Contact Email Address: **anlittle@southernco.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 5-4-06	3. PSD Number (if applicable): PSD-FL-377
2. Project Number(s): 0090180-003-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

☒ Air construction permit.

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

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

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

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

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

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

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

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

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

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

Application Comment

Oleander Power Project, L.P. (OPP) is planning to construct and operate one additional simple-cycle CTG at the existing OPP facility. Five simple-cycle CTGs were originally permitted under construction permit 0090180-001-AC, PSD-FL-258, however, only four CTGs were constructed and currently operate under Title V Operating Permit No. 0090180-002-AV. The new simple-cycle CTG will be a General Electric 7FA, nominal 190-megawatt (MW) CTG (designated as Unit 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 CTG will operate under same operating limits as the four existing CTGs, i.e. 3,390 total hours of operation per turbine during any calendar year, of which 1,000 hours of operation per turbine while burning low-sulfur distillate fuel oil.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
005	Nominal 190 MW simple cycle gas turbine, CT-5	AC1A	$7,500

Application Processing Fee

Check one: ☒ Attached - Amount: $ 7,500 ☐ Not Applicable

Ref: 62-4.050(4)(a)(1), F.A.C.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1.	Owner/Authorized Representative Name : **James O. Vick**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Gulf Power Company** Street Address: **One Energy Place** City: **Pensacola** State: **Florida** Zip Code: **32520**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(850) 444 - 6311** ext. Fax: **(850) 444 - 6217**
4.	Owner/Authorized Representative Email Address: **jovick@southernco.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.* James O Vick 5/3/06 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 NW 98th Street** City: **Gainesville** State: **Florida** Zip Code: **32606**	
3. Professional Engineer Telephone Numbers... Telephone: **(352) 332 - 0444** ext. **11351** 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   4/28/06

Signature   Date

(seal)

* 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) **520.1** North (km) **3,137.6**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **28/21/58** Longitude (DD/MM/SS) **80/47/41**	
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: **Allison Little**
2. Facility Contact Mailing Address... Organization/Firm: **Gulf Power Company** Street Address: **One Energy Place** City: **Pensacola** State: **Florida** Zip Code: **32520-0328**
3. Facility Contact Telephone Numbers: Telephone: **(850) 444 - 6537** ext. Fax: **(850) 444 – 6217**
4. Facility Contact Email Address: **anlittle@southernco.com**

Facility Primary Responsible Official

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

1. Facility Primary Responsible Official Name:
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:	

FACILITY INFORMATION

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**

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, Modification, or Plantwide Applicability Limit (PAL): ☒ 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), F.A.C.): ☐ Attached, Document ID:_________ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:_________ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **Section 7.0** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) 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

FACILITY INFORMATION

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 190 MW simple cycle combustion turbine – Unit 5

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

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			**49**	☒ Yes ☐ No

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

10. Generator Nameplate Rating: **190 MW**

11. Emissions Unit Comment:
Unit 5 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-NOx 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: **2,004.9 (LHV)** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	days/week **3,390*** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat rate is lower heating value (LHV) at 100 percent load, 32 ^{o}F, fuel-oil firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.** *** Maximum of 3,390 hours per year, of which 1,000 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: **CT 5**	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: **60** feet	7. Exit Diameter: **22** feet
8. Exit Temperature: **1,111** °F	9. Actual Volumetric Flow Rate: **2,575,837** 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: **1.956**	5. Maximum Annual Rate: **6,630.8**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: *	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: **929**
10. Segment Comment: **Fuel heat content (field 9) represents lower heating value (LHV).** ***Sulfur content of fuel shall be less than 1 grain per 100 standard cubic feet.**		

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: **15.153**	5. Maximum Annual Rate: **15,153**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **132**
10. Segment Comment: **Fuel heat content (field 9) represents lower heating value (LHV).**		

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			**NS**
3-VOC			**NS**
4-SO2			**EL**
5-PM			**NS**
6-PM10			**NS**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual 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: **351.6** lb/hour **243.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **351.6 LB/HR** Reference: **General Electric**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 62.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,390 hrs/yr and 336.8 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum of 3,390 hours per year, of which 1,000 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**	4. Equivalent Allowable Emissions: **62.5** lb/hour tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to NO_x limits of 40 CFR Part 60, Subpart KKKK (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: **42.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **336.8** lb/hour tons/year **(at ISO conditions)**
5. Method of Compliance: **NOx CEMS**	
6. Allowable Emissions Comment (Description of Operating Method): **Unit is also subject to NO_x limits of 40 CFR Part 60, Subpart KKKK (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: **62.5 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **62.5** lb/hour 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 NO_x limits of 40 CFR Part 60, Subpart KKKK (NSPS). Limit applicable for natural 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: **336.8 lb/hr (at ISO conditions)**	4. Equivalent Allowable Emissions: **336.8** lb/hour 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 NO_x limits of 40 CFR Part 60, Subpart KKKK (NSPS). Limit applicable for distillate fuel oil-firing.**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual 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: **72.0** lb/hour **83.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **72.0 LB/HR** Reference: **General Electric**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 41.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,390 hrs/yr and 68.1 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum of 3,390 hours per year, of which 1,000 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 __ of __

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

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual 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: **110.8** lb/hour **58.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **110.8 LB/HR** Reference: **General Electric**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly emission rate based on 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 4.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,390 hrs/yr and 106.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum of 3,390 hours per year, of which 1,000 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 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**	4. Equivalent Allowable Emissions: **4.9** lb/hour tons/year **(at ISO conditions)**
5. Method of Compliance: **Use of pipeline quality natural gas (sulfur content less than 1 grain 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% sulfur (by weight) fuel oil**	4. Equivalent Allowable Emissions: **106.0** lb/hour 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**	
6. Allowable Emissions Comment (Description of Operating Method): **Limit applicable for distillate fuel oil-firing.**	

$\frac{1s}{100 ft^3}$ 4.9 $\frac{lb}{hr}$ 11.711 + 26.5 = 38.211

1s

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual 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: **12.3** lb/hour **12.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **12.3 LB/HR** Reference: **General Electric**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Hourly emission rate based on 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 5.9 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,390 hrs/yr and 11.7 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.

11. Potential, Fugitive, and Actual Emissions Comment:

Maximum of 3,390 hours per year, of which 1,000 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:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual 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/PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **34.0** lb/hour **38.5** 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: **General Electric**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Hourly emission rate based on 100 percent load, 32°F, fuel oil-firing case. Annual emissions based on 18.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 2,390 hrs/yr and 34.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Maximum of 3,390 hours per year, of which 1,000 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 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 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: **10% opacity**	4. Equivalent Allowable Emissions: **34.0** lb/hour **N/A** tons/year
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 1

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:
7. Continuous Monitor Comment: **Required by 40 CFR Part 75 (Acid Rain Program); Specific monitor information not currently available.**	

Continuous Monitoring System: Continuous Monitor ___ of ___

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: 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(10) 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(4)(d), 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

Additional Requirements for Title V Air Operation Permit Applications

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

ATTACHMENT A-1

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT A-1

SOUTHERN COMPANY
OLEANDER POWER PROJECT

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter (PM) emissions that may result from operations include:

- Vehicular traffic on paved and unpaved roads.
- Windblown dust from paved and unpaved roads.
- Miscellaneous operational/maintenance activities.

The following techniques will be used to prevent unconfined PM emissions on an as-needed basis:

- Chemical or water application to unpaved roads and parking areas.
- Sweeping and general maintenance of paved roads and parking areas.
- Landscaping or planting of vegetation.
- Other techniques, as necessary.

ATTACHMENT A-2

REGULATORY APPLICABILITY ANALYSES

Table A2-1. 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)		005	General recordkeeping and reporting requirements.
Performance Tests	§60.8		005	Conduct performance tests as required by EPA or FDEP. **(potential future requirement).**
Compliance with Standards	§60.11(a) thru (d), and (f)		005	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		005	Cannot conceal an emission, which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		005	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		005	General procedures regarding reporting deadlines.
Subpart KKKK – Standards of Performance for Stationary Combustion Turbines				
Standards for Nitrogen Oxides	§60.4320 §60.4325		005	Establishes NO_x emission standards for combustion turbines >850 MMBtu/hr of 15 ppmvd at 15 percent O_2 (or 0.43 lb/MWhr) for natural gas-firing; 42 ppmvd at 15 percent O_2 (or 1.3 lb/MWhr) for firing fuels other than natural gas.
Standards for Sulfur Dioxide	§60.4330		005	Establishes SO_2 emission standards of 0.90 lb/MWhr gross output or 0.060 lb/MMBtu heat input.

Table A2-1. 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 KKKK – Standards of Performance for Stationary Combustion Turbines				
General Compliance Requirements	§60.4333		005	Operate and maintain combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices.
Monitoring Requirements	§60.4335 §60.4360		005	Install, calibrate, maintain, and operate continuous monitoring system or continuous emission monitoring system (CEMs) if using water or steam injection. Monitor fuel flow rate or gross electrical output, as applicable. Monitor total sulfur content of fuel.
Reporting Requirements	§60.4375		005	Submit excess emissions report and results of annual performance test, if applicable.
Performance Tests	§60.4400		005	Initial performance test as required by §60.8. Subsequent Performance Tests, if applicable.
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 Oleander Power Project.
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 Oleander Power Project.

Table A2-1. 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)		005	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		005	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		005	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		005	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.

Table A2-1. 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)		005	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to Oleander Power Project.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		005	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and (c)		005	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		005	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A – General				
Prohibitions	§75.5		005	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		005	General monitoring requirements.

Table A2-1. 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
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		005	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)		005	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)		005	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		005	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		005	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		005	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		005	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		005	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		005	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).

Table A2-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		005	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		005	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		005	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		005	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		005	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		005	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		005	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		005	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		005	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		005	General reporting requirements.

Table A2-1. 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
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		005	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		005	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)		005	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		005	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)**.

Table A2-1. 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
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		005	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		005	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		Oleander Power Project will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		Oleander Power Project personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		Oleander Power Project will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Oleander Power Project will not produce any products containing ozone depleting substances.

Table A2-1. 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
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Oleander Power Project 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.
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		Oleander Power Project personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.

Table A2-1. 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
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Oleander Power Project 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.
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 CTs 1A-2D will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention		X		Oleander Power Project will not store any chemicals that are subject to provisions of 40 CFR Part 68.

Table A2-1. 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 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 Oleander Power Project.

Source: ECT, 2006.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 13)

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 Oleander Power Project.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial construction 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)**

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 2 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation criteria.
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.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.
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.			005	NSPS Subpart KKKK; 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.			005	Acid Rain Program; see Table A-2A for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-2A for detailed federal regulatory citations.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
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.
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 Oleander Power Project.
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.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
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 Oleander Power Project.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.
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.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to Oleander Power Project.
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. **(potential future requirement)**.
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement)**.
Forms and Instructions	62-210.900, F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Unit 5 CT.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to Oleander Power Project.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			005	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 13)

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

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
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.			005	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.			005	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			005	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.			005	Defines revision procedures and automatic amendments **(potential future requirement)**..

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 13)

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

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
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 Oleander Power Project.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to Oleander Power Project.
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.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 12 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
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 Oleander Power Project.
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.
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 not located in a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.

Table A2-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 13 of 13)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to Oleander Power Project.
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, 2006.

ATTACHMENT A-3

FUEL ANALYSES OR SPECIFICATIONS

ATTACHMENT A-3

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.048
Propane	0.426
I-butane	0.091
N-butane	0.098
Pentane	0.064
Nitrogen	0.462
Methane	95.394
CO_2	0.894
Ethane	2.523
Other Characteristics	
Heat content	1,035 Btu/ft^3 with 14.73 psia, dry
Specific gravity	0.587
Sulfur content (maximum)	1.0 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: OPP, 2006.

ATTACHMENT A-3

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Density, kg/L (average)	
at 60°F	0.8531
at 80°F	0.8455
Heat of combustion, Btu/lb (average)	
Gross	19,563
Net	18,410
Hydrogen, percent by weight (average)	12.64
Carbon, percent by weight (average)	87.09
Nitrogen, percent by weight (average)	0.02
Ash, percent by weight (maximum)	0.01
Sulfur, percent by weight (maximum)	0.05
Trace constituents, ppm	
Sodium	<0.1
Vanadium	<0.1
Potassium	<0.1
Lead	<0.1
Calcium	<0.1
Magnesium	<0.1

Note: Btu/lb = British thermal units per pound.
kg/L = kilograms per liter.
ppm = parts per million.

Source: OPP, 2006.

APPENDIX B

EMISSION RATE CALCULATIONS

Table B-1. Oleander Power Project, SCCT Unit 5
CT Operating Scenarios - General Electric 7FA CT

Case	Ambient Temperature (oF)	Load (%)	Simple Cycle Unit 5	Evaporative Cooling	Annual Profile (hr/yr)	Natural Gas Firing	Fuel Oil Firing
1	32	100	X			X	X
2	32	75	X			X	X
3	32	50	X			X	X
4	59	100	X		2,390 (gas), 1,000 (oil)	X	X
5	59	75	X			X	X
6	59	50	X			X	X
7	95	100	X			X	X
8	95	100	X	X		X	X
9	95	75	X			X	X
10	95	50	X			X	X

SCCT - simple cycle combustion turbine
CT - combustion turbine

Sources: OPP, 2006.
ECT, 2006.

Table B-2. Oleander Power Project, SCCT Unit 5
CT Hourly Emission Rates - General Electric 7FA 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)
32	1	100	18.0	2.27	5.2	0.66	0.4	0.05	0.0313	0.00394
	2	75	18.0	2.27	4.2	0.53	0.3	0.04	0.0253	0.00319
	3	50	18.0	2.27	3.4	0.42	0.3	0.03	0.0202	0.00255
59	4	100	18.0	2.27	4.9	0.62	0.4	0.05	0.0297	0.00374
	5	75	18.0	2.27	4.0	0.51	0.3	0.04	0.0242	0.00304
	6	50	18.0	2.27	3.2	0.41	0.2	0.03	0.0194	0.00244
95	7	100	18.0	2.27	4.5	0.57	0.3	0.04	0.0270	0.00340
	8	100	18.0	2.27	4.7	0.59	0.4	0.05	0.0282	0.00356
	9	75	18.0	2.27	3.7	0.47	0.3	0.04	0.0223	0.00281
	10	50	18.0	2.27	3.0	0.37	0.2	0.03	0.0178	0.00225
		Maximums	**18.0**	**2.27**	**5.2**	**0.66**	**0.4**	**0.05**	**0.0313**	**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)
32	1	100	9.0	65.9	8.31	9.9	43.9	5.53	2.5	6.3	0.79
	2	75	9.0	52.8	6.65	9.7	34.7	4.38	2.4	5.0	0.63
	3	50	9.0	41.8	5.27	10.1	28.6	3.60	2.5	4.1	0.51
59	4	100	9.0	62.5	7.87	9.8	41.5	5.23	2.5	5.9	0.75
	5	75	9.0	50.4	6.35	9.8	33.4	4.21	2.5	4.8	0.60
	6	50	9.0	40.0	5.04	10.2	27.7	3.49	2.6	4.0	0.50
95	7	100	9.0	56.8	7.16	9.8	37.6	4.73	2.4	5.4	0.68
	8	100	9.0	59.5	7.50	9.6	38.7	4.88	2.4	5.5	0.70
	9	75	9.0	46.6	5.87	9.9	31.2	3.93	2.5	4.5	0.56
	10	50	9.0	36.8	4.64	10.6	26.3	3.31	2.6	3.8	0.47
		Maximums	**9.0**	**65.9**	**8.31**	**10.6**	**43.9**	**5.53**	**2.6**	**6.3**	**0.79**

[1] Filterable and condensible PM, excluding H_2SO_4 mist.

[2] Based on natural gas sulfur content of 1.0 gr/100 ft^3.

[3] Based on 5.0% 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.

Table B-3. Oleander Power Project, SCCT Unit 5
CT Hourly Emission Rates - General Electric 7241FA 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)
32	1	100	34.0	4.28	110.8	13.96	8.5	1.07	0.028	0.0035
	2	75	34.0	4.28	88.8	11.18	6.8	0.86	0.022	0.0028
	3	50	34.0	4.28	70.0	8.82	5.4	0.68	0.018	0.0022
59	4	100	34.0	4.28	106.0	13.36	8.1	1.02	0.027	0.0034
	5	75	34.0	4.28	85.7	10.80	6.6	0.83	0.022	0.0027
	6	50	34.0	4.28	67.6	8.52	5.2	0.65	0.017	0.0022
95	7	100	34.0	4.28	96.1	12.11	7.4	0.93	0.024	0.0031
	8	100	34.0	4.28	99.6	12.55	7.6	0.96	0.025	0.0032
	9	75	34.0	4.28	78.8	9.92	6.0	0.76	0.020	0.0025
	10	50	34.0	4.28	62.0	7.82	4.7	0.60	0.016	0.0020
		Maximums	**34.0**	**4.28**	**110.8**	**13.96**	**8.5**	**1.07**	**0.028**	**0.0035**

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)
32	1	100	42.0	351.6	44.30	14.1	72.0	9.07	4.2	12.3	1.55
	2	75	42.0	279.3	35.19	13.8	55.7	7.02	4.1	9.5	1.20
	3	50	42.0	218.0	27.47	14.5	45.8	5.77	4.3	7.9	0.99
59	4	100	42.0	336.8	42.44	13.9	68.1	8.58	4.2	11.7	1.47
	5	75	42.0	269.6	33.97	13.9	54.2	6.83	4.2	9.3	1.17
	6	50	42.0	210.5	26.52	14.6	44.7	5.63	4.4	7.7	0.97
95	7	100	42.0	305.3	38.47	13.9	61.4	7.74	4.2	10.5	1.33
	8	100	42.0	316.4	39.86	13.8	63.4	7.99	4.1	10.9	1.37
	9	75	42.0	247.9	31.24	14.1	50.7	6.39	4.2	8.7	1.09
	10	50	42.0	193.1	24.33	15.3	42.9	5.40	4.6	7.3	0.93
		Maximums	**42.0**	**351.6**	**44.30**	**15.3**	**72.0**	**9.07**	**4.6**	**12.3**	**1.55**

[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 5.0% 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, 2006.
GE, 2006.

Table B-4. Oleander Power Project, SCCT Unit 5
CT Emission Rates - General Electric 7241FA CT
Natural Gas-Firing: Hazardous Air Pollutants

Lead = .0296 lb/hr × 2890 / 2000 =

= .0428 TPY

Maximum Hourly Heat Input: (Case 1)	1,817	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,722	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	2,390	hrs/yr

Pollutant	Emission Factor[1] (lb/10^6 Btu)	HAP Emissions (Per CT)		
		(lb/hr)[2]	(g/s)[2]	(ton/yr)[3]
1,3-Butadiene	4.30E-08	7.82E-05	9.85E-06	8.85E-05
Acetaldehyde	4.00E-06	7.27E-03	9.16E-04	8.23E-03
Acrolein	6.40E-07	1.16E-03	1.47E-04	1.32E-03
Benzene	1.20E-06	2.18E-03	2.75E-04	2.47E-03
Ethylbenzene	3.20E-06	5.82E-03	7.33E-04	6.58E-03
Formaldehyde[4]	2.19E-04	3.98E-01	5.01E-02	4.50E-01
Lead[5]		3.13E-02	3.94E-03	3.54E-02
Naphthalene	1.30E-07	2.36E-04	2.98E-05	2.67E-04
Polycyclic Aromatic Hydrocarbons (PAH)	2.20E-07	4.00E-04	5.04E-05	4.53E-04
Propylene Oxide	2.90E-06	5.27E-03	6.64E-04	5.97E-03
Toluene	1.30E-05	2.36E-02	2.98E-03	2.67E-02
Xylene	6.40E-06	1.16E-02	1.47E-03	1.32E-02

.3765 lb/hr × 2,890 hrs / 2000 =

.544 TPY

[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, 32°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.

[5] Lead emission factor of 0.016 lb/MMft^3 was used from AP-42 draft dated 5/98.

Sources: ECT, 2006.
GE, 2006.

Table B-5. Oleander Power Project, SCCT Unit 5
CT Emission Rates - General Electric 7241FA CT
Distillate Fuel Oil-Firing: Hazardous Air Pollutants

Lead:

Maximum Hourly Heat Input: (Case 1)	2,005	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,919	10^6 Btu/hr
Maximum Annual Hours: (Case 4)	1,000	hrs/yr

Pollutant	Emission Factor[1] ($lb/10^6$ Btu)	HAP Emissions (Per CT) (lb/hr)[2]	(g/s)[2]	(ton/yr)[3]	
1,3-Butadiene	1.60E-05	3.21E-02	4.04E-03	1.54E-02	
Arsenic	1.10E-05	2.21E-02	2.78E-03	1.06E-02	
Benzene	5.50E-05	1.10E-01	1.39E-02	5.28E-02	
Beryllium	3.10E-07	6.22E-04	7.83E-05	2.98E-04	
Cadmium	4.80E-06	9.62E-03	1.21E-03	4.61E-03	
Chromium	1.10E-05	2.21E-02	2.78E-03	1.06E-02	500 hrs = .1105
Formaldehyde[4]	2.31E-04	4.63E-01	5.83E-02	2.21E-01	
Lead	1.40E-05	2.81E-02	3.54E-03	1.34E-02	@500 = .0067
Manganese	7.90E-04	1.58E+00	2.00E-01	7.58E-01	
Mercury	1.20E-06	2.41E-03	3.03E-04	1.15E-03	@500= .000575 or 5.75×10^{-4}
Naphthalene	3.50E-05	7.02E-02	8.84E-03	3.36E-02	
Nickel	4.60E-06	9.22E-03	1.16E-03	4.41E-03	
PAH	4.00E-05	8.02E-02	1.01E-02	3.84E-02	
Selenium	2.50E-05	5.01E-02	6.32E-03	2.40E-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, 32°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, 2006.
GE, 2006.

Table B-6. Oleander Power Project, SCCT Unit 5
CT Emission Rates - General Electric 7241FA CT
Hazardous Air Pollutants; Annual Summary

Pollutant	HAP Emissions Unit 5			
	Gas-Firing (ton/yr)	Oil-Firing (ton/yr)	Totals (ton/yr)	
1,3-Butadiene	8.85E-05	1.54E-02	1.54E-02	
Acetaldehyde	8.23E-03	N/A	8.23E-03	
Acrolein	1.32E-03	N/A	1.32E-03	
Arsenic	N/A	1.06E-02	1.06E-02	
Benzene	2.47E-03	5.28E-02	5.53E-02	
Beryllium	N/A	2.98E-04	2.98E-04	
Cadmium	N/A	4.61E-03	4.61E-03	
Chromium	N/A	1.06E-02	1.06E-02	
Ethylbenzene	6.58E-03	N/A	6.58E-03	
Formaldehyde	**4.50E-01**	2.21E-01	6.72E-01	.6545
Lead	3.54E-02	1.34E-02	4.89E-02	.0495
Manganese	N/A	**7.58E-01**	**7.58E-01**	
Mercury	N/A	1.15E-03	1.15E-03	$.575 \times 10^{-3}$
Naphthalene	2.67E-04	3.36E-02	3.39E-02	
Nickel	N/A	4.41E-03	4.41E-03	
PAH	4.53E-04	3.84E-02	3.88E-02	
Propylene Oxide	5.97E-03	N/A	5.97E-03	
Selenium	N/A	2.40E-02	2.40E-02	
Toluene	2.67E-02	N/A	2.67E-02	
Xylene	1.32E-02	N/A	1.32E-02	
Maximum Individual HAP	0.45	0.76	0.76	
Maximum Total HAPs	0.55	1.19	1.74	

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

Sources: ECT, 2006.
GE, 2006.

Formaldehyde @ 500 hrs oil = .544 gas
+ .1105 oil
.6545 TPY

Lead @ 500 hrs oil = .0428
+ .0067
.0495

Table B-7. Oleander Power Project, SCCT Unit 5
Annual Emission Rates

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 5	4 - NG	2,390	62.5	74.6	41.5	49.6	5.9	7.1
Unit 5	4 - Oil	1,000	336.8	168.4	68.1	34.0	11.7	5.8
		Totals	**N/A**	**243.1**	**N/A**	**83.7**	**N/A**	**12.9**

Source	Case	Annual Operations (hrs/yr)	Emission Rates							
			PM/PM_{10}		SO_2		H_2SO_4		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 5	4 - NG	2,390	18.0	21.5	4.9	10.62 5.9	0.38	0.5	0.030	0.035
Unit 5	4 - Oil	1,000	34.0	17.0	106.0	53.0	8.12	4.1	0.027	0.013
		Totals	**N/A**	**38.5**	**N/A**	26.5 **58.9**	**N/A**	**4.5**	**N/A**	**0.049**

Sources: GE, 2006.
ECT, 2006.
OPP, 2006.

Table B-8. Oleander Power Project, SCCT Unit 5
40 CFR Part 60 Subpart KKKK

Temp. (°F)	Case	Load (%)	SO_2 (Natural gas) (lb/hr)	SO_2 (Natural gas) (lb/MMBtu)[1]	SO_2 (Distillate Oil) (lb/hr)	SO_2 (Distillate Oil) (lb/MMBtu)[1]
32	1	100	5.2	0.003	110.8	0.055
	2	75	4.2	0.003	88.8	0.055
	3	50	3.4	0.003	70.0	0.055
59	4	100	4.9	0.003	106.0	0.055
	5	75	4.0	0.003	85.7	0.055
	6	50	3.2	0.003	67.6	0.055
95	7	100	4.5	0.003	96.1	0.055
	8	100	4.7	0.003	99.6	0.055
	9	75	3.7	0.003	78.8	0.055
	10	50	3.0	0.003	62.0	0.055
		Maximums	**5.2**	**0.003**	**110.8**	**0.055**

[1] 40 CFR Part 60 Subpart KKKK SO_2 emission limit is 0.9 lb/MWh or 0.06 lb/MMBtu.

Source: ECT, 2006.

Table B-9A. Oleander Power Project, SCCT Unit 5
CT Exhaust Data - General Electric 7FA CT
Natural Gas-Firing

A. Exhaust MW

		Exhaust Gas Composition - Volume %									
Component	MW (lb/mole)	100 % Load				75 % Load			50 % Load		
		32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
	Case	1	4	7	8	2	5	9	3	6	10
	Evap. Cooling				X						
Ar	39.944	0.90	0.89	0.88	0.89	0.88	0.89	0.88	0.91	0.89	0.89
N_2	28.016	74.84	74.45	73.28	72.88	74.81	74.45	73.31	74.91	74.56	73.47
O_2	32.000	12.64	12.56	12.32	12.15	12.55	12.54	12.41	12.84	12.86	12.88
CO_2	44.010	3.80	3.79	3.75	3.78	3.85	3.80	3.71	3.71	3.65	3.49
H_2O	17.008	7.82	8.31	9.77	10.31	7.91	8.32	9.69	7.64	8.04	9.28
	Totals	100.00	100.00	100.00	100.01	100.00	100.00	100.00	100.01	100.00	100.01
Exhaust MW (lb/mole)		28.37	28.31	28.14	28.08	28.37	28.31	28.14	28.39	28.33	28.17
Exhaust Flow (lb/sec)		1,117.42	1,060.29	968.13	1,002.58	884.51	853.30	802.95	726.98	705.49	674.87
Exhaust Temp. (°F)		1,085	1,111	1,149	1,135	1,134	1,154	1,184	1,185	1,200	1,200
(K)		858	873	894	886	885	896	913	914	922	922
Exhaust O_2 (Vol %, Dry)		13.71	13.70	13.65	13.55	13.63	13.68	13.74	13.90	13.98	14.20

Sources: ECT, 2006.
GE, 2006.

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Table B-9B. Oleander Power Project, SCCT Unit 5
CT Exhaust Data - General Electric 7FA CT
Natural Gas-Firing

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)									
	100 % Load				75 % Load			50 % Load		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
Evap. Cooling				X						
ACFM	2,664,043	2,575,837	2,424,063	2,493,567	2,176,256	2,129,735	2,053,763	1,844,260	1,809,749	1,740,934
Velocity (fps)	116.8	112.9	106.3	109.3	95.4	93.4	90.0	80.9	79.3	76.3
Velocity (m/s)	35.6	34.4	32.4	33.3	29.1	28.5	27.4	24.6	24.2	23.3
SCFM, Dry[1]	839,235	793,776	717,749	740,352	663,847	638,750	595,687	546,731	529,350	502,356
SCFM (15% O_2, Dry)	1,022,401	968,901	881,494	922,722	818,223	781,872	722,745	648,468	620,476	570,682
ACFM (15% O_2, Dry)	2,991,685	2,882,847	2,686,219	2,787,390	2,470,165	2,390,039	2,250,364	2,020,321	1,950,738	1,794,189

Sources: ECT, 2006.
GE, 2006.

Table B-9C. Oleander Power Project, SCCT Unit 5
CT Exhaust Data - General Electric 7FA CT
Natural Gas-Firing

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)									
	100 % Load				75 % Load			50 % Load		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
Evap Cooling				X						
CO (ppmvd)	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
CO (15% O_2)	9.9	9.8	9.8	9.6	9.7	9.8	9.9	10.1	10.2	10.6
VOC (ppmvw)	2.8	2.8	2.7	2.7	2.8	2.8	2.7	2.8	2.8	2.7
VOC (ppmvd)[1]	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
VOC (15% O_2)	2.5	2.5	2.4	2.4	2.4	2.5	2.5	2.5	2.6	2.6

[1] Based on existing Title V operating permit condition.

Sources: ECT, 2006.
GE, 2006.

Table B-10A. Oleander Power Project, SCCT Unit 5
CT Exhaust Data - General Electric 7241FA CT
Distillate Fuel Oil-Firing

A. Exhaust MW

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %									
		100 % Load				75 % Load			50 % Load		
		32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
	Case	1	4	7	8	2	5	9	3	6	10
	Evap. Cooling				X						
Ar	39.944	0.85	0.85	0.84	0.83	0.86	0.85	0.84	0.88	0.86	0.85
N_2	28.016	71.46	71.06	70.27	70.04	71.61	71.35	70.68	72.21	71.97	71.43
O_2	32.000	11.18	11.02	10.86	10.80	11.00	11.02	11.05	11.50	11.54	11.78
CO_2	44.010	5.65	5.68	5.65	5.65	5.80	5.74	5.59	5.56	5.49	5.22
H_2O	17.008	10.87	11.39	12.39	12.68	10.74	11.05	11.84	9.86	10.15	10.72
	Totals	100.01	100.00	100.01	100.00	100.01	100.01	100.00	100.01	100.01	100.00
Exhaust MW (lb/mole)		28.27	28.21	28.09	28.05	28.31	28.26	28.15	28.39	28.34	28.24
Exhaust Flow (lb/sec)		1,132.23	1,074.83	976.60	1,010.58	876.08	853.81	802.70	715.32	699.04	672.48
Exhaust Temp. (°F)		1,064	1,095	1,138	1,122	1,134	1,152	1,183	1,185	1,200	1,200
(K)		846	864	888	879	885	895	913	914	922	922
Exhaust O_2 (Vol %, Dry)		12.54	12.44	12.40	12.37	12.32	12.39	12.53	12.76	12.84	13.19

Sources: ECT, 2005.
GE, 1998.

Table B-10B. Oleander Power Project, SCCT Unit 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		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
ACFM	2,672,194	2,593,984	2,432,406	2,495,243	2,160,167	2,132,344	2,051,498	1,815,011	1,792,659	1,730,684
Velocity (fps)	117.2	113.7	106.6	109.4	94.7	93.5	89.9	79.6	78.6	75.9
Velocity (m/s)	35.7	34.7	32.5	33.3	28.9	28.5	27.4	24.3	24.0	23.1
SCFM, Dry[1]	825,165	780,465	704,120	727,200	638,689	621,258	581,218	525,128	512,320	491,471
SCFM (15% O_2, Dry)	1,168,731	1,119,568	1,014,906	1,051,568	928,422	896,193	824,144	724,682	699,566	641,874
ACFM (15% O_2, Dry)	3,373,382	3,297,214	3,071,629	3,150,722	2,802,849	2,736,104	2,564,525	2,257,770	2,199,395	2,018,012

Sources: ECT, 2005.
GE, 1998.

**Table B-10C. Oleander Power Project, SCCT Unit 5
CT Exhaust Data - General Electric 7241FA CT
Distillate Fuel Oil-Firing**

C. Correction of GE CO and VOC Concentrations to 15% O_2, dry

	Flow Rates (ft^3/min)									
	100 % Load				75 % Load			50 % Load		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
CO (ppmvd)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO (15% O_2)	14.1	13.9	13.9	13.8	13.8	13.9	14.1	14.5	14.6	15.3
VOC (ppmvw)	5.3	5.3	5.3	5.2	5.4	5.3	5.3	5.4	5.4	5.4
VOC (ppmvd)[1]	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
VOC (15% O_2)	4.2	4.2	4.2	4.1	4.1	4.2	4.2	4.3	4.4	4.6

[1] Based on existing Title V operating permit condition.

Table B-11. Oleander Power Project, SCCT Unit 5
CT Fuel Flow Rate Data - General Electric 7241FA CT

A. Natural Gas-Firing

	100 % Load				75 % Load			50 % Load		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
Evap. Cooling				X						
Heat Input - LHV (MMBtu/hr)	1817.5	1721.9	1565.3	1638.3	1469.2	1402.7	1295.1	1175.8	1125.5	1035.2
Fuel Rate (lb/hr)	86,444	81,896	74,450	77,923	69,877	66,716	61,598	55,922	53,532	49,236
Fuel Rate (10^6 ft^3/hr)	1.956	1.853	1.685	1.764	1.581	1.510	1.394	1.266	1.212	1.114
Fuel Rate (lb/sec)	24.012	22.749	20.680	21.645	19.410	18.532	17.111	15.534	14.870	13.677

B. Distillate Fuel Oil-Firing

	100 % Load				75 % Load			50 % Load		
	32 °F	59 °F	95 °F	95 °F	32 °F	59 °F	95 °F	32 °F	59 °F	95 °F
Case	1	4	7	8	2	5	9	3	6	10
Evap. Cooling				X						
Heat Input - LHV (MMBtu/hr)	2004.9	1919.5	1739.8	1802.5	1606.6	1551.8	1425.6	1267.6	1223.7	1122.9
Fuel Rate (lb/hr)	110,768	106,049	96,121	99,585	88,760	85,733	78,764	70,035	67,609	62,038
Fuel Rate (10^3 gal/hr)	15.153	14.507	13.149	13.623	12.142	11.728	10.775	9.580	9.249	8.486
Fuel Rate (lb/sec)	30.769	29.458	26.700	27.663	24.656	23.815	21.879	19.454	18.780	17.233

Sources: ECT, 2005.
GE, 2006.

APPENDIX C

DISPERSION MODELING FILES