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BUREAU OF AIR REGULATION

March 19, 2008

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Florida Department of Environmental Protection
Division of Air Resource Management
111 South Magnolia Drive, Suite 4
Tallahassee, FL 32301

Via FedEx
Airbill No. 7926 6816 9042

Re: Tampa Electric Company
H.L. Culbreath Bayside Power Station
Air Construction Permit Application for
Eight Simple-Cycle Combustion Turbines (SCCTs)

Dear Ms. Vielhauer,

Tampa Electric Company (TEC) requests an air construction permit to install and operate eight simple-cycle combustion turbines (SCCTs) at its existing H.L. Culbreath Bayside Power Station (BPS). The BPS SCCT project consists of four Pratt & Whitney (P&W) FT8-3 SwiftPac aeroderivative CT units. Each P&W FT8-3 SwiftPac unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). The BPS P&W FT8-3 SCCTs will be fired exclusively with pipeline-quality natural gas and will operate in peaking service for no more than 2,500 hours per year per SCCT. The SCCTs will utilize water injection and oxidation catalyst technologies to control emissions of nitrogen oxides and carbon monoxide, respectively.

Please find the enclosed air construction permit application for Bayside's SCCTs..

TEC appreciates the cooperation of the Department in this matter. If you have any questions or comments, please contact me at (813) 228-1095.

Sincerely,

David M. Lukcic, P.E.
Manager – Environmental Projects
Environmental, Health & Safety

EHS/ich/DML152

Enclosure

c/enc: Mr. Jeff Koerner, FDEP
Mr. David Lloyd, EPA Region 4
Ms. Mara Grace Nasca, FDEP SW
Mr. Sterlin Woodard, EPCHC

BAYSIDE POWER STATION

SIMPLE-CYCLE COMBUSTION TURBINES UNITS 3 THROUGH 6

AIR CONSTRUCTION PERMIT APPLICATION

Prepared for:

TAMPA ELECTRIC
Tampa, Florida

Prepared by:

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

ECT No. 071286-0100

March 2008

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) plans to construct and operate eight simple-cycle combustion turbines (SCCTs) at its existing H.L. Culbreath Bayside Power Station (BPS). The BPS is located on Port Sutton Road in Tampa, Hillsborough County, Florida.

The BPS presently includes seven General Electric (GE) Model PG7241 FA natural gas-fired combustion turbine (CT)/heat recovery steam generator (HRSG) combined-cycle units that operate in conjunction with the existing F.J. Gannon Station Units 5 and 6 steam turbines. The seven BPS CT/HRSG units are grouped in two units designated as Units 1 and 2. BPS Units 1 and 2 repowered F.J. Gannon Station Units 5 and 6, respectively. BPS Unit 1 includes three CT/HRSGs designated as CT-1A, CT-1B, and CT-1C. BPS Unit 2 includes four CT/HRSGs designated as CT-2A, CT-2B, CT-2C, and CT-2D.

The BPS SCCT project consists of four Pratt & Whitney (P&W) FT8-3® SwiftPac™ aeroderivative CT units. Each P&W FT8-3® SwiftPac™ unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 megawatts (MW). The BPS P&W FT8-3® SCCTs will be fired exclusively with pipeline-quality natural gas and will operate in peaking service for no more than 2,500 hours per year (hr/yr) per SCCT. The SCCTs will utilize water injection and oxidation catalyst technologies to control emissions of nitrogen oxides (NO_x) and carbon monoxide (CO), respectively.

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

The existing BPS is located in an attainment area, is one of the 28 named prevention of significant deterioration (PSD) source categories (i.e., is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour [MMBtu/hr] heat input), and has potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). The proposed SCCT project will have potential emissions of one or more PSD pollutants above the PSD significant emissions rate thresholds. Consequently, the BPS SCCT project qualifies as a *major modification* to an existing major source and is subject to the PSD new source review (NSR) requirements of Section 62-212.400, F.A.C. Therefore, this report and application are also submitted to satisfy the permitting requirements contained in FDEP PSD Section 62-212.400, F.A.C.

The BPS SCCT project is not subject to the National Emissions Standards for Hazardous Air Pollutants (NESHAPs) for Stationary Combustion Turbines (Chapter 40, Part 63, Subpart YYYY, Code of Federal Regulations [CFR]) since the existing BPS is a minor source of hazardous air pollutants (HAPs), and the addition of the eight P&W SCCTs will not change that classification. In addition, the effectiveness of Subpart YYYY was stayed by U.S. Environmental Protection Agency (EPA) on August 18, 2004, for diffusion flame gas-fired turbines—the type of turbine proposed for the BPS SCCT project. The BPS SCCTs will be subject to the applicable requirements of New Source Performance Standard (NSPS) Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

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 ambient air quality standards (AAQS) and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the applicable state and federal emission standards.
- Section 5.0 provides an analysis of best available control technology (BACT).

- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on the Chassahowitzka National Wilderness Area (NWA) Class I area.
- Section 11.0 lists the references used in preparing the 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 BPS SCCT project will consist of four nominal 62-MW, simple-cycle P&W FT8-3® SwiftPac™ units. Each P&W FT8-3® SwiftPac™ unit consists of two SCCTs coupled to one common generator. Accordingly, there will be a total of eight SCCTs and four generators. The SCCTs will be fired exclusively with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per 100 standard cubic feet (gr S/100 scf). The SCCT project will also include two black start emergency diesel engine/generator sets. Excluding emergency conditions, the diesel engine/generator sets will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes. The emergency diesel engines will be fired with ultra-low-sulfur diesel (ULSD) fuel oil.

The planned construction start date for the SCCT project is the August 2008. The projected date for the facility to begin commercial operation is May 2009, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, the BPS SCCT project will have the potential to emit 321.6 tpy of NO_x, 46.8 tpy of CO, 25.0 tpy of particulate matter (PM)/particulate matter less than or equal to 10 micrometers aerodynamic diameter (PM_{10}), 18.6 tpy of sulfur dioxide (SO_2), and 13.5 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, the BPS SCCT project will potentially emit 2.1 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of organic compounds associated with natural gas combustion. Based on these annual emissions rate potentials, NO_x and PM/PM_{10} 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_{10}. The SCCTs will use the latest burner technologies to maximize combustion efficiency and minimize PM_{10} emissions rates and will be fired exclusively with pipeline-quality natural gas.
- Water injection technology is proposed as BACT for NO_x for the SCCTs. For all normal operating loads, SCCT NO_x exhaust concentrations will not exceed 25 parts per million by dry volume (ppmvd), corrected to 15-percent oxygen. This concentration is consistent with prior BACT determinations for simple-cycle aeroderivative CTs in peaking service. Cost effectiveness of selective catalytic reduction (SCR) control technology was determined to be \$14,564 per ton of NO_x. Because this cost exceeds values previously determined by FDEP to be cost effective, SCR control technology is considered economically unreasonable.
- The SCCT project is projected to emit NO_x and PM/PM_{10} in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the SCCT project qualifies for the Rule 62-212.400(3)(e), 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(279), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards

(NAAQS) attainment and PSD Class II increment consumption was not required.

- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below EPA-defined PSD Class I significant impact levels. Accordingly, a multisource interactive assessment of PSD Class I increment consumption was not required.
- Based on refined dispersion modeling, the SCCT project will not cause nor contribute to a violation of any NAAQS, Florida AAQS, or PSD increment for Class I or II areas.
- The ambient impact analysis also demonstrates that SCCT project impacts will be well below levels detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Chassahowitzka NWA) is located approximately 80 kilometers (km) north of the project site. The ambient impact analysis demonstrates that the SCCT project will have no adverse visibility and deposition impacts on this Class I area.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed new P&W SCCTs will be located at the existing BPS. The BPS is located on Port Sutton Road in Tampa, Hillsborough County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the BPS site location and nearby prominent geographical features.

The proposed SCCT project consists of four P&W FT8-3® SwiftPac™ aeroderivative CT units. Each P&W FT8-3® SwiftPac™ unit consists of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 MW. Total BPS SCCT project nominal gross generation capacity is 248 MW. The P&W FT8-3® SCCTs will be fired exclusively with pipeline-quality natural gas. The new SCCTs will operate in peaking service for no more than 2,500 hr/yr per SCCT and will normally operate between 50- and 100-percent load. The SCCT project will also include two black start emergency diesel engine/generator sets. Excluding emergency conditions, the diesel engine/generator sets will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes. The emergency diesel engines will be fired with ULSD fuel oil.

Combustion of natural gas in the SCCTs and ULSD fuel oil in the emergency diesel engines will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, H_2SO_4 mist, and minor amounts of HAPs. Emissions control systems proposed for the SCCTs include the use of water injection for control of NO_x; oxidation catalyst for abatement of CO and VOCs; and use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Emissions from the emergency diesel engines will comply with the requirements of NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

Figure 2-2 provides a site plan showing the BPS existing combined-cycle units and major facility structures and the proposed new SCCTs and emergency diesel engines. Additional details of the SCCTs are provided on Figure 2-3. Primary access to the BPS is from

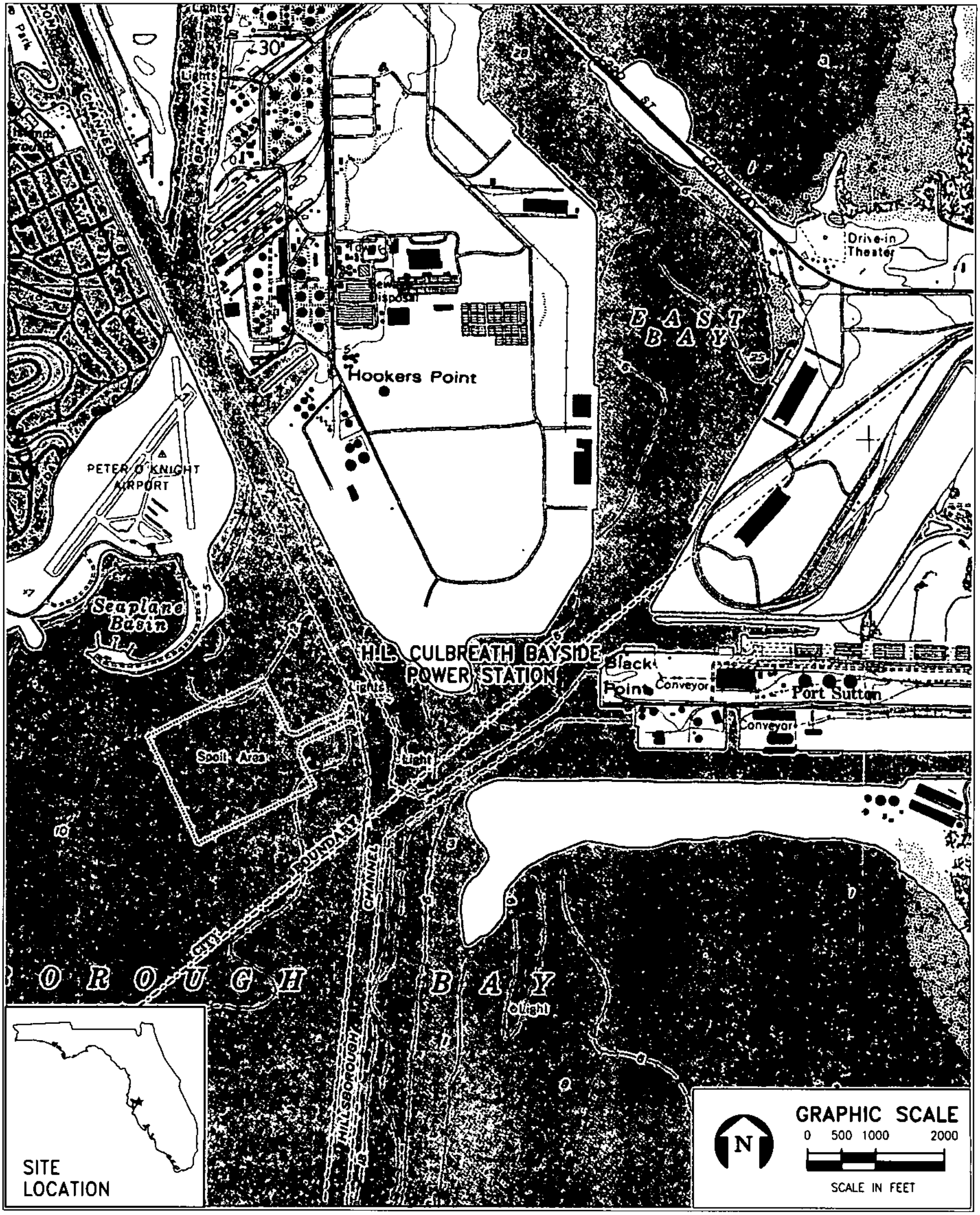

FIGURE 2-1.

H.L. CULBREATH BAYSIDE POWER STATION LOCATION AND SURROUNDINGS

Source: USGS Quad: Tampa, FL, 1981; ECT, 2008.

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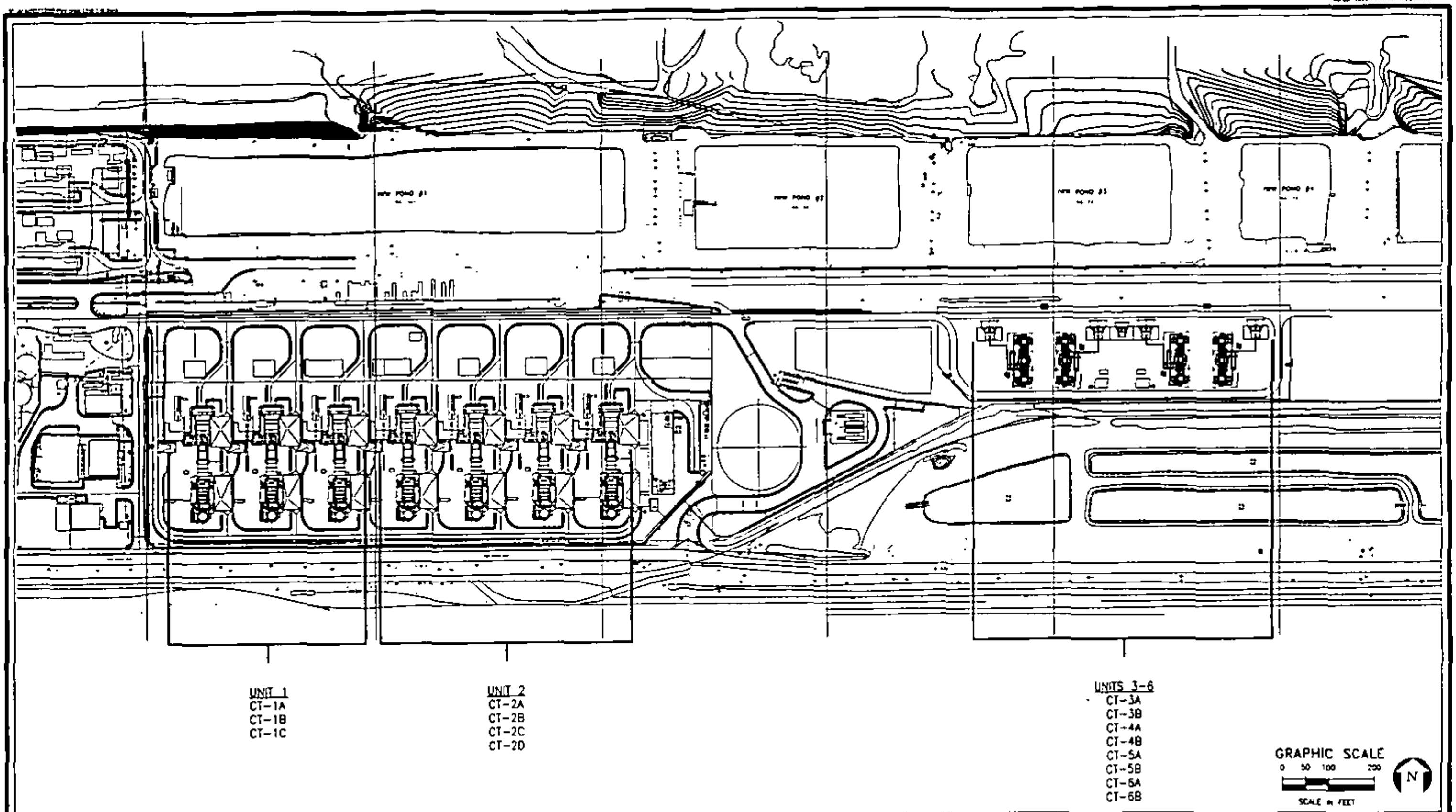

FIGURE 2-2.
H. L. CULBREATH BAYSIDE POWER STATION
UNITS 1, 2, AND 3-6 PLOT PLAN
Sources: Black & Veatch Co., 2006; ECT, 2006.

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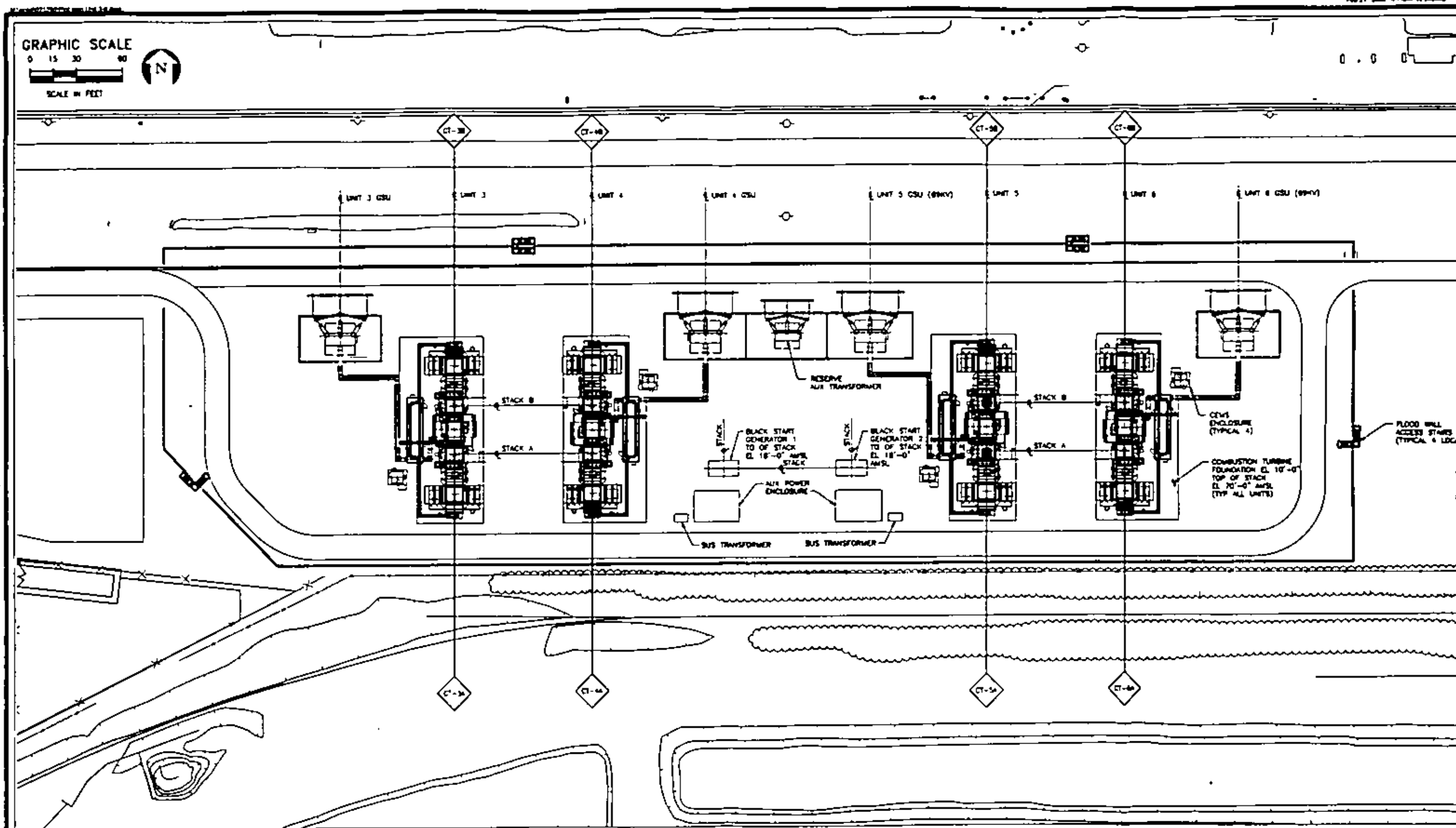

FIGURE 2-3.

H. L. CULBREATH BAYSIDE POWER STATION

UNITS 3-6 PLOT PLAN

Sources: Black & Veatch Co., 2006; ECT, 2008.

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Port Sutton Road on the south side of the site. The BPS entrance has security to control site access.

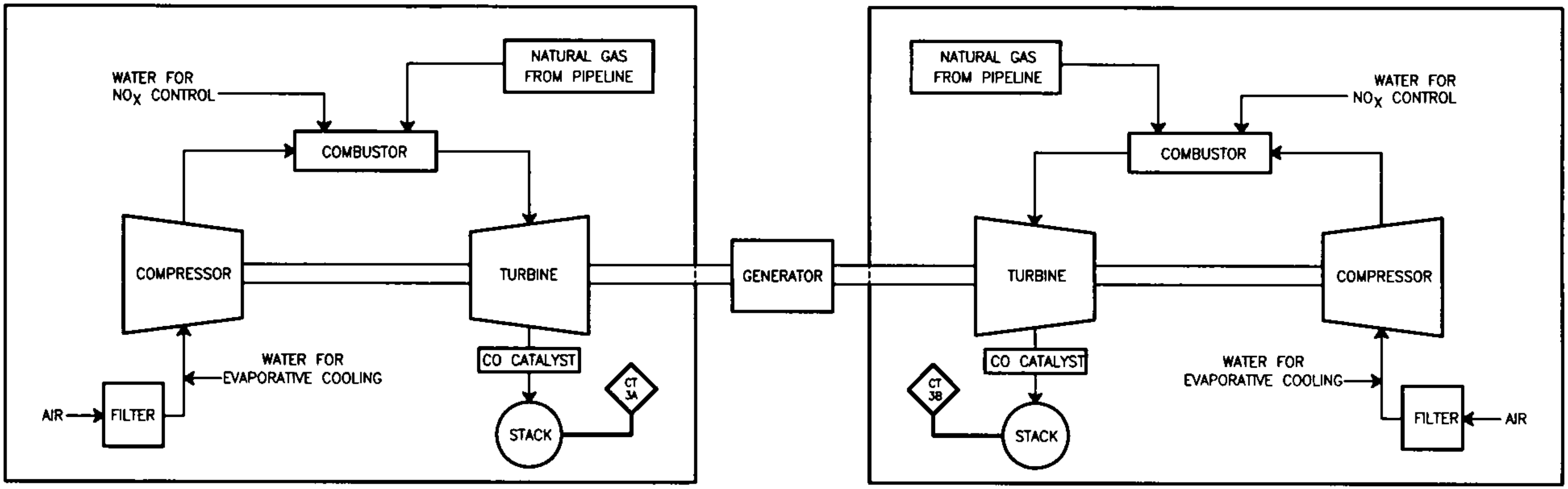
2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed BPS SCCT project will include four nominal 62-MW P&W FT8-3® SwiftPac™ units. Figure 2-4 presents a process flow diagram of the SCCT project.

CTs are heat engines that convert latent fuel energy into work using compressed hot gas as the working medium. CTs 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 CT compressor. At ambient temperatures above approximately 59 degrees Fahrenheit (°F), inlet air evaporative cooling (i.e., *fogging*) may be used to lower the inlet air temperature and provide additional electrical power. The CT 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 and burned in the CT's high-pressure combustors to produce hot exhaust gases. These high-pressure, hot gases expand and turn the CT's turbine to produce rotary shaft power, which is used to drive an electric generator as well as the CT combustion air compressor.

Normal operation is expected to consist of the SCCTs operating at rated load. Alternate operating modes include reduced load operation (i.e., between 50 and 100 percent of rated load) and inlet air evaporative cooling depending on power demands. As noted previously, the SCCTs will operate in peaking service for no more than 2,500 hr/yr per SCCT.

The aeroderivative SCCTs will use water injection to control NO_x air emissions. The use of low-sulfur natural gas in the SCCTs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. Oxidation catalyst will be employed to control CO and VOC emissions.



P&W FT8-3 SWIFT PAC SIMPLE CYCLE COMBUSTION TURBINE

FIGURE 2-4.

BPS----P&W SCCT PROCESS FLOW DIAGRAM

Source: ECT, 2008.

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2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant and H_2SO_4 mist SCCT emissions rates, respectively. Table 2-3 provides maximum hourly organic hazardous air pollutant emission rates. The highest hourly emissions rates for each pollutant are shown, taking into account load and ambient temperature to develop maximum hourly emissions estimates for each SCCT. Noncriteria pollutants consist primarily of trace amounts of organic compounds associated with the combustion of natural gas.

Maximum hourly emissions rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CT operations at low ambient temperature (i.e., 20°F) and full load. Appendix B provides the bases for these emissions rates.

Table 2-4 presents projected maximum annualized criteria and noncriteria emissions for the BPS SCCT project. For the SCCTs, the annual profile assumes full load operation for 2,500 hr/yr at an ambient temperature of 59°F with inlet air evaporative cooling. This represents a conservative estimate of annual emission rates since the annual average temperature for the Tampa Bay area is 72°F.

Table 2-5 provides stack parameters for the SCCTs. Stack parameters for the emergency diesel engines are shown in Table 2-6.

Table 2-1. Maximum Criteria Pollutant Emissions Rates for Three SCCT Loads and Three Ambient Temperatures (per SCCT)

SCCT Load (%)	Ambient Temperature (°F)	PM/PM_{10}		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.5	0.32	1.84	0.23	31.6	3.98	6.2	0.77	1.3	0.16	Neg.	Neg.
	59†	2.5	0.32	1.86	0.23	32.0	4.03	4.7	0.59	1.4	0.17	Neg.	Neg.
	90†	2.5	0.32	1.75	0.22	30.2	3.81	4.4	0.56	1.3	0.16	Neg.	Neg.
75	20	2.5	0.32	1.42	0.18	24.4	3.07	8.4	1.05	2.7	0.33	Neg.	Neg.
	59†	2.5	0.32	1.44	0.18	24.8	3.12	7.0	0.89	1.9	0.24	Neg.	Neg.
	90†	2.5	0.32	1.38	0.17	23.7	2.99	5.4	0.68	1.3	0.16	Neg.	Neg.
50	20	2.5	0.32	1.04	0.13	18.2	2.29	9.1	1.15	5.1	0.64	Neg.	Neg.
	59†	2.5	0.32	1.06	0.13	18.2	2.29	6.6	0.83	2.2	0.27	Neg.	Neg.
	90†	2.5	0.32	1.02	0.13	17.5	2.21	6.1	0.77	2.0	0.25	Neg.	Neg.

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

*Excludes H_2SO_4 mist.
†Emission rates reflect the use of evaporative cooling at ambient temperatures above approximately 59°F.

Sources: P&W, 2008.
ECT, 2008.

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

SCCT Load (%)	Ambient Temperature (°F)	H_2SO_4 Mist	
		lb/hr	g/s
100	20	0.21	0.027
	59*	0.21	0.027
	90*	0.20	0.025
75	20	0.16	0.021
	59*	0.17	0.021
	90*	0.16	0.020
50	20	0.12	0.015
	59*	0.12	0.015
	90*	0.12	0.015

Note: g/s = gram per second.

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

Sources: Environmental Consulting & Technology, Inc. (ECT), 2008
P&W, 2008.

Table 2-3. Maximum Organic HAP Emissions Rates for 100-Percent SCCT Load and Three Ambient Temperatures (per SCCT)

SCCT Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	7.14E-05	8.56E-06	6.64E-03	7.97E-04	1.06E-03	1.27E-04	1.99E-03	2.394E-04	5.32E-03	6.37E-04	1.18E-01	1.41E-02
	59*	7.23E-05	8.68E-06	6.73E-03	8.07E-04	1.08E-03	1.29E-04	2.02E-03	2.42E-04	5.38E-03	6.46E-04	1.19E-01	1.43E-02
	90*	6.82E-05	8.19E-06	6.35E-03	7.62E-04	1.02E-03	1.22E-04	1.90E-03	2.29E-04	5.08E-03	6.09E-04	1.13E-01	1.35E-02

SCCT Load (%)	Ambient Temperature (°F)	Naphthalene		Polycyclic Organic Matter		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	2.16E-04	2.59E-05	3.65E-04	4.38E-05	4.82E-03	5.78E-04	2.16E-02	2.59E-03	1.06E-02	1.27E-03
	59*	2.19E-04	2.62E-05	3.70E-04	4.44E-05	4.88E-03	5.85E-04	2.19E-02	2.62E-03	1.08E-02	1.29E-03
	90*	2.06E-04	2.48E-05	3.49E-04	4.19E-05	4.60E-03	5.52E-04	2.06E-02	2.48E-03	1.02E-02	1.22E-03

Note: Neg. = negligible

*Emission rates reflect the use of evaporative cooling at ambient temperatures above approximately 59°F.

Source: ECT, 2008.

Table 2-4. Maximum Annualized Emissions Rates (tpy)

Pollutant	SCCT Project
NO_x	321.6
CO	46.8
PM/PM_{10}*	25.0
SO_2	18.6
VOC	13.5
H_2SO_4 mist	2.1
1,3-Butadiene	0.00072
Acetaldehyde	0.067
Acrolein	0.011
Arsenic	0.00066
Benzene	0.020
Beryllium	0.000039
Cadmium	0.0036
Chromium	0.0046
Ethylbenzene	0.054
Formaldehyde	1.2
Lead	0.0017
Manganese	0.0013
Mercury	0.00086
Naphthalene	0.0022
Nickel	0.0069
PAHs	0.0037
Propylene oxide	0.049
Selenium	0.000079
Toluene	0.22
Xylene	0.11
Total HAPs	1.7

Note: PAH = polycyclic aromatic hydrocarbon.

*Filterable and condensable particulate matter.

Sources: P&W, 2008.
TEC, 2008.
ECT, 2008.

Table 2-5. Stack Parameters for Three SCCT Loads and Three Ambient Temperatures (Per SCCT)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	60.0	18.3	828	715	99.6	30.4	9.5	2.90
	59*	60.0	18.3	893	752	101.3	30.9	9.5	2.90
	90*	60.0	18.3	917	765	97.6	29.8	9.5	2.90
75	20	60.0	18.3	748	671	83.3	25.4	9.5	2.90
	59*	60.0	18.3	817	709	84.8	25.9	9.5	2.90
	90*	60.0	18.3	864	735	82.3	25.1	9.5	2.90
50	20	60.0	18.3	701	645	67.7	20.6	9.5	2.90
	59*	60.0	18.3	767	682	68.2	20.8	9.5	2.90
	90*	60.0	18.3	814	708	66.7	20.3	9.5	2.90

*Stack data reflect the use of evaporative cooling at ambient temperatures above approximately 59°F.

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

Sources: P&W, 2008.
ECT, 2008.

Table 2-6. Stack Parameters for Emergency Generator Diesel Engines

Exhaust Parameter	Emergency Generator (Per Engine)
Height (ft)	15
Diameter (ft)	0.67
Exit temperature (°F)	955
Flow Rate (acfm)	6,046
Exit velocity (ft/s)	288.7

Note: acfm = actual cubic foot per minute.
ft/s = foot per second.

Sources: Caterpillar, 2007.
ECT, 2008.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

As a result of the 1977 Clean Air Act (CAA) Amendments (1990), EPA has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are intended to protect the public health, and secondary NAAQS are intended to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Florida has also adopted AAQS (reference Section 62-204.240, F.A.C.). Table 3-1 presents the current national and Florida AAQS.

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The BPS is located south of downtown Tampa in Hillsborough County. Hillsborough County is presently designated in 40 CFR 81.310 as "cannot be classified" for SO_2 and for total suspended particulates [TSPs] for that portion of Hillsborough County that falls within the area of a circle having a center point at the intersection of U.S. Highway 41 South and State Road 60 and a radius of 12 km. Hillsborough County is designated "unclassifiable/attainment" for CO, ozone (1-hour and 8-hour standards), and particulate matter with an aerodynamic diameter equal to or less than a nominal 2.5 microns ($PM_{2.5}$), and designated "cannot be classified or better than national standards" for nitrogen dioxide (NO_2). For lead, Hillsborough County is designated "unclassifiable" for the area encompassed within a radius of 5 km centered on universal transverse mercator [UTM] coordinates: 364.0 km east, 3,093.5 km north, zone 17, in the city of Tampa.

Hillsborough County is designated attainment (for ozone, CO, and NO_2) and unclassifiable (for SO_2, PM_{10}, and lead) by Section 62-204.340, F.A.C. Hillsborough County is also classified as an air quality maintenance area for ozone (entire county), for PM (that portion of Hillsborough County which falls within the area of a circle having a center point at the intersection of U.S. Highway 41 South and State Road 60 and a radius of

Table 3-1. National and Florida AAQS (micrograms per cubic meter [$\mu g/m^3$] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2	3-hour[1]		1,300	1,300
	24-hour[1]	365		260
	Annual[2]	80		60
PM_{10}	24-hour[3]	150	150	150
	Annual[4]			50
$PM_{2.5}$	24-hour[5]	35	35	
	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
	8-hour[8]	0.075	0.075	
NO_2	Annual[2]	100	100	100
Lead	Calendar quarter arithmetic mean	1.5	1.5	1.5

[1]Not to be exceeded more than once per calendar year.
[2]Arithmetic mean.
[3]The standards are attained when the expected number of days per calendar year with a 24-hour average concentration above 150 $\mu g/m^3$, as determined in accordance with 40 CFR 50 Appendix K, is equal to or less than 1.
[4]The standards are attained when the expected annual arithmetic mean concentration, as determined in accordance with 40 CFR 50 Appendix K, is less than or equal to 50 $\mu g/m^3$.
[5]98th percentile concentration, as determined in accordance with 40 CFR 50 Appendix N.
[6]Arithmetic mean concentration, as determined in accordance with 40 CFR 50 Appendix N.
[7]Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.
[8]Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentrations over a 3-year period are less than or equal to the standard, as determined by 40 CFR 50, Appendix I. The 8-hour ozone standard was reduced from 0.08 to 0.075 ppmv on March 12, 2008.

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

12 km), and for lead (the area encompassed within a radius of 5 km centered on UTM coordinates: 364.0 km east, 3,093.5 km north, zone 17) by Section 62-204.340, F.A.C.

Although the Florida rules currently include a 1-hour ozone AAQS (reference Rule 62-204.240[4], F.A.C.), on the federal level, EPA revoked this standard in Florida effective June 15, 2005. FDEP plans to adopt both the 8-hour ozone and $PM_{2.5}$ NAAQS and remove the 1-hour ozone AAQS in a single rulemaking project.

3.2 NONATTAINMENT NSR APPLICABILITY

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

3.3 PSD NSR APPLICABILITY

The BPS SCCT project will have potential emissions greater than 1 or more of the PSD significant emission rates listed in Rule 62-212.200(278), F.A.C. Accordingly, the SCCT project qualifies as a major modification to an existing 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 SCCT project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x and PM/PM_{10} 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 the SCCT project.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(4)(c), F.A.C., an analysis of BACT is required for each pollutant emitted by The SCCT project in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(40), F.A.C., BACT is:

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

Pollutant	SCCT Project Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	321.6	40	Yes
CO	46.8	100	No
PM	25.0	25	Yes
PM_{10}	25.0	15	Yes
SO_2	18.6	40	No
Ozone/VOC	13.5	40	No
Lead	0.016	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not present	3	No
H_2SO_4 mist	2.1	7	No
Total reduced sulfur (S) (including hydrogen sulfide [H_2S])	Not present	10	No
Reduced sulfur compounds (including H_2S)	Not present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride [HCl])	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
For the pollutants listed above, and for major stationary sources locating within 10 km of a Class I area having an impact equal to or greater than 1 $\mu g/m^3$, 24-hour average	N/A	Any amount	No

Sources: Rule 62-210.200(278), F.A.C.
TEC, 2008.
P&W, 2008.
ECT, 2008.

> "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account: (1) energy, environmental, and economic impacts, and other costs, (2) all scientific, engineering, and technical material and other information available to the Department, and (3) the emission limiting standards or BACT determinations of Florida and any other state, 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 NSPS, NESHAPs, or any other emission limitation established by state regulations.

BACT analyses must be conducted using the following five step *top-down* approach:

1. All available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology

has reached the licensing and commercial sales phase of development). An available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies that are determined to be technically infeasible, based on physical, chemical, and engineering principals, are eliminated from further consideration.

3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. 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 accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control alternative is not applicable due to adverse energy, environmental, or economic impacts, it is rejected as BACT and the next most stringent control alternative is then considered.
5. 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 evaluated pollutant.

This five-step procedure for conducting a BACT analysis is described in Chapter B of EPA's Draft New Source Review Manual dated October 1990.

The BACT emission limit established during the initial permitting process will be enforceable over the life of the unit. As a result, the BACT analysis must take into account the full range of possible fuels, operating conditions, operating system fluctuations, and normal wear-and-tear on the units and control systems. EPA's Environmental Appeals Board (EAB) has recognized that "permitting agencies have the discretion to set BACT limits at levels that do not necessarily reflect the highest possible control efficiencies but, rather will allow permittees to achieve compliance on a consistent basis" (Three Mountain Power, PSD Appeal No. 01-05 at 21 [May 30, 2001] citing: In re Masonite Corp., 5 E.A.D. 560-61 [EAB 1994] ["There is nothing inherently wrong with setting an emission limitation that takes into account a reasonable safety factor."]; and In re Knauf Fiber Glass, GmbH, PSD Appeal Nos. 99-8 to -72, slip op. at 21 [EAB, Mar. 14, 2000] ["The inclusion of a reasonable safety factor in the emission limitation is a legitimate method of deriving a specific emission limitation that may not be exceeded."]).

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(7), 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 that exceed the PSD significant emission rate thresholds shown in Table 3-2).

Preconstruction ambient air monitoring for a period of up to 1 year is generally required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided 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(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-3). 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 SCCT project is discussed in Section 8.2.

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* (GAQM) 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(279), F.A.C., significant impact level (SIL), as presented in Table 3-4. EPA has proposed SILs for Class I areas—these levels are provided in Table 3-5.

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 (HSH) short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* 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

Table 3-3. PSD *De Minimis* Ambient Impact Levels

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

Source: Rule 62-212.400(3)(e)1., F.A.C.

Table 3-4. FDEP Significant Impact Levels

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

Source: Rule 62-210.200(279), F.A.C.

Table 3-5. EPA Significant Impact Levels—Class I Areas

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	0.1
	24-Hour	0.2
	3-Hour	1.0
PM_{10}	Annual	0.2
	24-Hour	0.3
NO_2	Annual	0.1

Source: EPA Proposed, 1996; 61FR 38249.

the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the 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 that 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 $PM_{2.5}$, became effective on October 17, 2006. 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 3-6.

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

Table 3-6. PSD Allowable Increments

Pollutant	Averaging Time	Class ($\mu g/m^3$) I	II	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.

submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

The ambient impact analyses for the BPS SCCT project are provided in Sections 6.0 (Methodology), 7.0 (PSD Class II areas), and 10.0 (PSD Class I areas).

3.4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(8), F.A.C., requires additional impact analyses for three areas: associated growth, soils and vegetation impact, and visibility impairment. The level of analysis for each area should be commensurate with the scope of the project. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

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

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

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project. Section 9.0 provides the additional impact analyses for the BPS SCCT project.

3.5 HAZARDOUS AIR POLLUTANT REQUIREMENTS

Florida relies on the requirements of the CAA with respect to the regulation of hazardous (also known as toxic) air pollutants. These federal requirements include a comprehensive set of technology-based emission standards referred to as NESHAPs. These standards establish HAP emission limitations for a wide variety of industrial source categories. Recent NESHAPs (i.e., those adopted after the 1990 CAA Amendments) reflect maximum achievable control technology (MACT). Section 4.2 provides a discussion of the NESHAPs program and its applicability to The SCCT project.

4.0 STATE AND FEDERAL EMISSION STANDARDS

4.1 NEW SOURCE PERFORMANCE STANDARDS (NSPS)

Section 111 of the CAA, Standards of Performance of New Stationary Sources, requires EPA establish federal emission standards for source categories that cause or contribute significantly to air pollution. These standards are intended to promote use of the best air pollution control technologies, taking into account the cost of such technology and any other non-air quality, health, and environmental impact and energy requirements. These standards apply to sources that have been constructed or modified since the proposal of the standard. Since December 23, 1971, EPA has promulgated more than 75 standards. The NSPS are codified in the Code of Federal Regulations at 40 CFR 60.

The BPS SCCT project will include eight SCCTs and two emergency generator diesel engines. These SCCTs and diesel engines will be subject to the applicable requirements of NSPS Subparts KKKK and IIII, respectively, as discussed in the following sections.

4.1.1 NSPS SUBPART KKKK—STATIONARY COMBUSTION TURBINES

Subpart KKKK establishes emission limits for CT/HRSG units that commenced construction after February 18, 2005, and that have a heat input at peak load equal to greater than 10.7 gigajoules (10 MMBtu/hr) based on the higher heating value (HHV) of the fuel.

The BPS SCCTs will be fired exclusively with natural gas for up to 2,500 hr/yr. NSPS Subpart KKKK specifies emission limitations, monitoring, reporting, and recordkeeping requirements for NO_x and SO_2. Applicable NSPS Subpart KKKK emission standards for the SCCTs units are summarized as follows:

- $\underline{NO_x}$—25 ppmvd at 15-percent oxygen, or 1.2 pounds per megawatt-hour (lb/MWh) gross energy output.
- $\underline{SO_2}$—0.90 lb/MWh gross energy output, or 0.060 pound per million British thermal units (lb/MMBtu).

The BPS SCCTs will comply with the applicable requirements of NSPS Subpart KKKK.

4.1.2 NSPS SUBPART IIII—STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

NSPS Subpart IIII is applicable to owners and operators of stationary compression ignition (CI) internal combustion engines (ICE) that commence construction after July 11, 2005, where the CI ICE are manufactured after April 1, 2006 (and are not fire pump engines), or manufactured after July 1, 2006 (for certified National Fire Protection Association fire pump engines).

NSPS Subpart IIII specifies emission limitations, monitoring, reporting and recordkeeping requirements for NO_x, CO, nonmethane hydrocarbons, and PM. Applicable NSPS Subpart IIII emission standards for the BPS emergency diesel generator CI ICEs are summarized as follows:

- Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in Section 60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.
- Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must: (a) reduce NO_x emissions by 90 percent or more, or limit the emissions of NO_x in the stationary CI internal combustion engine exhaust to 1.6 grams per kilowatt-hour (1.2 grams per horsepower-hour), and (b) reduce PM emissions by 60 percent or more or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 gram per kilowatt-hour (0.11 gram per horsepower-hour).

The BPS emergency diesel engines will have a displacement of less than 30 liters per cylinder and will comply with the applicable requirements of NSPS Subpart IIII.

4.2 NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The provisions of the CAA that address the control of HAP emissions, or air toxics, are found in Section 112. Section 112 of the CAA includes provisions for the promulgation of NESHAPs, or MACT standards, as well as several related programs to enhance and support the NESHAPs program. Section 112 requires EPA to publish and regularly update (at least every 8 years) a list of all categories and subcategories of major and area sources that emit HAPs. The Section 112(c) list of source categories was initially published in the Federal Register (FR) on July 16, 1992, and has been periodically revised thereafter. EPA must promulgate regulations establishing emission standards (NESHAPs) for each category or subcategory of major sources and area sources of HAPs that are listed pursuant to Section 112(c). The standards must require the maximum degree of emission reduction that EPA determines to be achievable by each particular source category. Different criteria for MACT apply for new and existing sources. Less stringent standards, known as generally available control technology (GACT) standards, are allowed at the EPA Administrator's discretion for area sources.

As required by Section 112 of the CAA, EPA promulgated a final NESHAPs for stationary combustion turbines (40 CFR 63, Subpart YYYY) on March 5, 2004. However, the 40 CFR 63 NESHAPs are only applicable to *major* HAP sources (i.e., facilities that have potential emissions of any individual HAP of 10 tpy or more, and potential emissions of total HAPs of 25 tpy or more). The BPS, including the SCCT project, will have potential HAP emission rates below these thresholds and, therefore, is a minor source of HAPs. Accordingly, the 40 CFR 63 NESHAPs are not applicable to the BPS emission sources, including the SCCT project. In addition, the effectiveness of Subpart YYYY was stayed by EPA on August 18, 2004, for diffusion flame gas-fired turbines—the type of turbine proposed for the BPS SCCT project.

NESHAPs Subpart ZZZZ applies to new stationary reciprocating internal combustion engines (RICE) with a site-rating of more than 500 brake horsepower (bhp) that commence construction after December 19, 2002. New RICE that operate exclusively as emergency units are subject only to initial notification requirements. However, Subpart ZZZZ is only applicable to RICE located at major sources of HAP emissions. Accordingly, Subpart ZZZZ of 40 CFR 63 NESHAPs is not applicable to the BPS emergency generator diesel engines.

4.3 ACID RAIN PROGRAM

The overall goal of the acid rain program (ARP) is to achieve significant environmental and public health benefits through reductions in emissions of SO_2 and NO_x, the primary causes of acid rain. To achieve this goal at the lowest cost to society, the program employs both traditional and innovative, market-based approaches for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

Title IV of the CAA sets a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing more than 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 MW and all new utility units.

For SO_2, the ARP introduced an allowance trading system that harnesses the incentives of the free market to reduce pollution. Under this cap-and-trade program, affected existing utility units (i.e., those in operation prior to November 15, 1990) are allocated allowances based on their historical fuel consumption and a specific emission rate. Each allowance permits a unit to emit 1 ton of SO_2 during or after a specified year. For each ton of SO_2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold, or banked. Anyone may acquire allowances and participate in the trading system. However, regardless of the number of allowances a source holds, it may not emit at levels that would violate federal or state limits set under Title I of the

CAA to protect public health. During Phase II of the program (now in effect), the CAA set a permanent ceiling (or cap) of 8.95 million allowances for total annual SO_2 allowance allocations to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. New utility units (i.e., those that commence operation on and after November 15, 1990) are not allocated any SO_2 allowances and must obtain such allowances annually from the ARP SO_2 allowance market in amounts equal to their actual SO_2 emission rates.

The CAA also required a 2-million-ton reduction in NO_x emissions by the year 2000. A significant portion of this reduction has been achieved by coal-fired utility boilers that will be required to install low-NO_x burner technologies and to meet new emissions standards. The ARP NO_x emission reduction requirements are only applicable to existing utility units (i.e., those in operation prior to November 15, 1990).

The BPS SCCTs will be subject to the ARP since they will be *new utility units* (i.e., will commence operation after November 15, 1990) and will serve a generator that produces electricity for sale. As noted previously, new utility units do not receive any SO_2 allowance allocations. Accordingly, TEC will need to annually obtain SO_2 allowances from the ARP SO_2 allowance market in amounts equal to the SCCT's actual SO_2 emission rates. The NO_x component of the ARP does not apply to new utility units.

4.4 CLEAN AIR INTERSTATE RULE

On March 10, 2005, EPA issued the final Clean Air Interstate Rule (CAIR). The objective of CAIR is to assist states with $PM_{2.5}$ and 8-hour ozone nonattainment areas to achieve attainment by reducing precursor emissions at sources located in 28 states (including Florida) situated upwind of these nonattainment areas. Based on regional dispersion modeling, EPA determined that these 28 upwind states significantly contribute to $PM_{2.5}$ and 8-hour ozone nonattainment in downwind areas. Florida emission sources are projected to significantly contribute to $PM_{2.5}$ nonattainment areas located in Georgia (Macon and Atlanta) and Alabama (Birmingham) and to an 8-hour ozone nonattainment area in Georgia (Atlanta).

The CAIR reductions of precursor emissions address annual SO_2 and NO_x emissions (for reductions in annual and daily average ambient $PM_{2.5}$ impacts) and ozone season (May through September) NO_x emissions (for reductions in 8-hour average ambient ozone impacts). The SO_2 and NO_x reductions will be implemented by means of a regional two-phase cap-and-trade program. For SO_2, the first cap begins in calendar year 2010 and extends through 2014. For NO_x, the first cap begins in calendar year 2009 and also extends through 2014. The second phase cap for both pollutants becomes effective in calendar year 2015 and thereafter. The SO_2 caps will reduce current ARP SO_2 emissions by 50 percent in Phase I and by 65 percent in Phase II. The NO_x caps reflect NO_x emission rates of 0.15 and 0.125 lb/MMBtu for the first and second phase caps, respectively.

For each phase cap, CAIR assigns SO_2 and NO_x emission budgets (in units of tpy and in units of tons per ozone season) to each affected upwind state. These state emission budgets were developed by EPA based on the application of cost-effective control technologies (i.e., flue gas desulfurization [FGD]) for SO_2 and SCR for NO_x. The affected states were required to submit revised state implementation plans (SIPs) within 18 months (i.e., by September 11, 2006) for EPA review and approval. Florida's proposed SIP revisions implementing CAIR were submitted to EPA Region 4 on March 16, 2007, for review and approval in accordance with EPA's abbreviated SIP approval process. The SIPs will provide details as to the procedures that will be used to allocate the state NO_x and SO_2 budgets to individual sources.

Following SIP approval and allocation of the state SO_2 and NO_x budgets to individual emission sources, emission units at these sources must possess sufficient SO_2 and NO_x allowances such that actual emissions (as measured by continuous emissions monitorring system [CEMS]) do not exceed the allocations for each control period beginning in 2009 (for NO_x) and 2010 (for SO_2). Sources that have actual emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances on the open market. Emission sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances on the open market.

Florida has adopted EPA's 40 CFR 96 CAIR NO_x and SO_2 Trading Programs for SIPs by reference in Section 62-204.800, F.A.C. Florida's implementation of the Federal CAIR is set forth at Section 62-296.470, F.A.C.

EPA's model NO_x trading program includes provisions for allocating NO_x allowances to new utility units (those that are placed in service in 2001 or later) such as the BPS SCCTs (i.e., a new source set-aside). Similar to the ARP, there are no provisions for a new source set-aside with respect to CAIR SO_2 allowances. For NO_x allowances, new units will be allocated allowances from the new source set-aside until they have established a baseline and are included in the shared pool. NO_x allowance allocations from the new source set-aside pool will be made to new utility units on a pro-rata basis.

4.5 CLEAN AIR MERCURY RULE

On March 15, 2005, EPA issued the final Clean Air Mercury Rule (CAMR). The purpose of CAMR is to reduce national coal-fired power plant mercury emissions from the current level of 48 to 15 tpy by means of a two-phase cap-and trade program. The first phase national mercury cap (with a cap of 38 tpy) becomes effective in 2010 while the second 15-tpy cap becomes effective in 2018 and thereafter.

CAMR also establishes stack mercury emission standards applicable to new sources (i.e., those constructed, modified, or reconstructed after January 30, 2004.) Similar to CAIR, CAMR assigns mercury budgets (in units of tpy) to each state for each phase cap. The first phase mercury cap represents the cobenefits that will be achieved by CAIR (i.e., installation of FGD and SCR controls). The second phase mercury cap is based on the cumulative effect of FGD/SCR cobenefits and on EPA projections regarding the availability and removal efficiency of future mercury controls (e.g., activated carbon injection [ACI]).

The NSPS program serves as the regulatory authority for CAMR. Accordingly, the revisions to NSPS Subpart Da were effective upon proposal (i.e., January 30, 2004). CAMR also includes a new NSPS, Subpart HHHH, which contains EPA's model mercury trading program. Under the terms of revised NSPS Subpart Da, states must submit plans by November 17, 2006, that address the state EGU mercury caps for 2010 and 2018 for EPA review and approval. The state plans will provide details as to the procedures that will be used to allocate the state mercury budgets to individual coal-fired utility units. For each control period, sufficient mercury allowances must be held to cover the actual mercury emissions for all mercury budget units at a source. Although mercury allowances will be allocated on a unit-by-unit basis, compliance with the CAMR mercury allowance program is determined on a plant-wide basis.

As described previously for the CAIR state SO_2 and NO_x budgets, following SIP approval and allocation of the state mercury budgets to individual emission sources, these sources must possess sufficient mercury allowances to cover their actual emission rates (as continuously measured either by CEMS or sorbent trap monitoring systems) for each control period beginning in 2010. Emission sources that have actual mercury emissions in excess of their allocation will need to reduce actual emission rates or purchase additional allowances. Emission sources that have surplus allowances may bank the allowances for use in any future control period or sell the surplus allowances. Revised SIPs that address the CAMR requirements were required to be submitted to EPA by November 17, 2006.

Florida has adopted NSPS Subpart HHHH by reference in Section 62-204.800, F.A.C., subject to the provisions set forth at Section 62-296.480, F.A.C. This latter rule provides Florida's implementation of the Federal CAMR. Florida's proposed SIP revisions implementing CAMR were submitted to EPA Region 4 on December 29, 2006.

The CAMR only applies to coal-fired units and therefore is not applicable to the BPS SCCTs. In addition, on February 8, 2008, the U.S. Court of Appeals for the District of Columbia vacated both EPA's action delisting electric utility steam generators from the CAA Section 112(c) HAP source category list and the CAMR. Essentially, the Court ruled that EPA did not have the authority to delist electric utility steam generators from the HAP source category list and therefore could not adopt a mercury cap-and-trade program for electric utilities. EPA now has 2 years to develop NESHAPs for existing power plants.

4.6 FLORIDA EMISSION STANDARDS

FDEP emission standards for stationary sources are contained in Chapter 62-296, Stationary Sources—Emission Standards, F.A.C. General pollutant emission limit standards are included in Section 62-296.320, F.A.C. Sections 62-296.401 through 62-296.418, F.A.C., specify emission standards for 18 categories of sources. Sections 62-296.470 and 62-296.480 address CAIR and CAMR requirements, respectively. Sections 62-296.500 through 62-296.570, F.A.C., establish reasonably available control technology (RACT) requirements for VOC and NO_x emitting facilities. RACT requirements for lead and PM are found in Sections 62-296.600 through 62-296.605 and 62-296.700 through 62-296.712, F.A.C., respectively. Florida has adopted the federal NSPS and NESHAPs by reference in Section 62-204.800, F.A.C.

With respect to the BPS SCCT project, the general Rule 62-296.320(4)(b), F.A.C., visible emission limitation of 20-percent opacity will apply to all point (i.e., stack) emission sources. None of the emission standards specified in Sections 62-296.401 through 62-296.418, F.A.C., are applicable to the BPS SCCTs or emergency generator diesel engines. The VOC, NO_x, lead, and PM RACT requirements do not apply to emission units that are subject to NSR permitting, and therefore are not applicable to the BPS SCCT project. NSPS Subparts KKKK and IIII will be applicable to the BPS SCCTs and emergency generator diesel engines, respectively. There are no 40 CFR 61 or 40 CFR 63 NESHAPs applicable to the BPS SCCT project.

The BPS SCCT project will comply with all of the applicable Florida emission standards noted previously.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method. As previously described in Section 3.4.1, the top-down methodology consists of the following five steps:

- Step 1—Identify all available control technologies for each PSD pollutant subject to review.
- Step 2—Eliminate all technically infeasible control technologies.
- Step 3—Rank the remaining control technologies by control effectiveness.
- Step 4—Evaluate the feasible control technologies, beginning with the most efficient, with respect to economic, energy, and environmental impacts.
- Step 5—Select as BACT the most effective control technology that is not rejected based on adverse economic, environmental, and/or energy impacts.

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 RACT/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC information system database.
- Recent permits for combined-cycle CT power projects.
- FDEP BACT determinations for similar facilities.
- 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.

If the top-case control technology with the highest removal efficiency is selected as BACT, an assessment of collateral environmental impacts is conducted to determine whether such impacts would deem the control technology unacceptable. If the most efficient control technology is not selected as BACT, an assessment of energy, environmental, and economic impacts is then performed. If assessed, the economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual, Sixth Edition (EPA, 2002). Tables 5-1 and 5-2 summarize the specific factors used in estimating capital and annual operating costs, respectively.

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 defined by Rule 62-210.200(40), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR 60), NESHAP (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, Stationary Sources—Emission Standards, F.A.C.). The NSPS, NESHAPs, and Florida emission standards applicable to the BPS SCCT project were previously discussed in Sections 4.1, 4.2, and 4.6, respectively. The BACT emission limitations proposed for the BPS SCCT project will comply with the applicable federal and state standards cited in these sections.

As shown in Table 3-2 of Section 3.0, annual BPS SCCT project emissions of NO_x and PM/PM_{10} are projected to exceed the PSD significance rates for these pollutants. A BACT analysis is therefore required for each BPS SCCT project emission unit that will emit these pollutants. Accordingly, BACT analyses were conducted for the BPS SCCTs and emergency generator diesel engines.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
<u>Direct Capital Costs (DCC)</u>	
Instrumentation	0.10 × equipment cost
Sales tax	0.07 × equipment cost
Freight	0.05 × equipment cost
Purchased equipment cost (PEC)	Instrumentation + sales tax + freight
Foundations and supports	0.08 × PEC
Handling and erection	0.14 × PEC
Electrical	0.04 × PEC
Piping	0.02 × PEC
Insulation	0.01 × PEC
Painting	0.01 × PEC
<u>Indirect Capital Costs (IIC)</u>	
General facilities	0.05 × DCC
Engineering and home office fees	0.10 × DCC
Process contingency	0.05 × DCC
<u>Project Contingency (PC)</u>	0.15 × (DCC + IIC)
<u>Total Plant Cost (TPC)</u>	DCC + IIC + PC
<u>Other Costs (OC)</u>	
Preproduction cost	0.02 × TPC
Inventory capital	Initial reagent
<u>Total Capital Investment (TCI)</u>	TPC + OC

Sources: EPA, 2002.
ECT, 2008.

Table 5-2. Annual Operating Cost Factors

Cost Item	Factor
<u>Total Direct Costs (TDC)</u>	
Maintenance labor and materials	0.015 × TCI
Reagent (for SCR control system)	Anhydrous ammonia $480 ton delivered, dry ammonia basis
Electricity (for SCR control system)	0.105 × uncontrolled NO_x (lb/hr) × SCR control efficiency (%/100) × hr/yr × power cost ($/kW-hr)
Catalyst replacement	Catalyst replacement cost× capital recovery factor
Energy penalty	0.2 percent of CT output per inch of pressure drop
<u>Total Indirect Costs (TIC)</u>	TCI × capital recovery factor
<u>Total Annual Cost (TAC)</u>	TDC + TIC

Sources: EPA, 2002.
ECT, 2008.

The SCCTs and emergency generator diesel engines will emit pollutants associated with fuel combustion including NO_x and PM/PM_{10}. BACT analyses were therefore conducted for each of these combustion-related PSD pollutants.

The SCCTs are the principal BPS SCCT project emission sources. The SCCTs will be fired exclusively with pipeline-quality natural gas. The SCCTs will be equipped with water injection to reduce the formation of NO_x. This system of process design and use of clean fuels will reduce emissions of the NO_x and PM/PM_{10} to very low levels.

Control technology analyses using the five-step top-down BACT method are provided for in Section 5.3 (for NO_x–SCCTs), Section 5.4 (for NO_x– emergency generator diesel engines), Section 5.5 (for PM/PM_{10}–SCCTs), and Section 5.6 (for PM/PM_{10}-emergency generator diesel engines).

5.2 EVALUATION OF ALTERNATIVE ELECTRICAL GENERATION TECHNOLOGIES

As discussed in Section 5.1, the first step in a BACT determination process is to identify all available control technologies that could potentially be used to minimize the emissions for the pollutant under evaluation. Control technologies typically considered in a BACT analysis include process modifications that reduce the formation of pollutants, and post-process emission control systems that reduce emissions after the pollutants are formed. An example of the former is the use of low-NO_x burners to alter the combustion process and reduce the formation of NO_x. The use of SCR to reduce NO_x following its formation in the combustion process is an example of a postprocess emission control system. These types of control technologies, when applicable, are appropriately considered in a BACT analysis.

Evaluation of process alternatives that would involve completely redefining the design of the proposed process are not required to be considered (reference the 1990 Draft New Source Review Workshop Manual, Section IV.A.3). Alternative electrical generating processes, such as solid fuel, frame-type CTs or combined-cycle generation systems, represent completely different power generation plant designs compared to the natural gas-fired aeroderivative SCCT technology selected for the BPS SCCT project. While all electrical generation technologies generate electricity, the technical basis for the SCCT technology is substantially different from a solid fuel, frame-type CT, or combined-cycle system. Since a solid fuel, frame-type CT, or combined-cycle system represents a completely different process compared to aeroderivative SCCT technology, a BACT analysis of these alternative electrical generation technologies is not required because these process alternatives would redefine the design of the BPS SCCT project.

Although a BACT analysis of alternative electrical generation technologies is not required, TEC conducted an analysis of available electrical generation technologies prior to selecting the aeroderivative SCCT technology. The aeroderivative SCCT technology was selected for the following reasons:

- Ensures black start capability in 2009 at the BPS, as required by North American Electric Reliability Council (NERC).[1]
- Meets state operating reserve requirements more efficiently with quick-start capability than via spinning reserve on a larger asset.[2]
- Meets a 271-MW reserve margin shortage in the winter of 2010 and a 2.3-percent year-over-year load growth thereafter.
- Diversifies generating asset size and improve generating efficiency. The aeroderivative SCCTs approximate 50-MW summer capacity fulfills an asset niche presently unavailable in TEC's portfolio (consisting mainly of 150- to 460-MW summer capacities generators).[3] Likewise, the aeroderivative SCCTs will lend TEC's system generating efficiency with an approximate 9,500-British-thermal-units-per-kilowatt-hour (Btu/kWh) heat rate (for 50 MW). Currently TEC sees approximately 14,000 Btu/kWh (for 50 MW) from its larger turbines.

[1] Black start is defined by the Florida Reliability Coordinating Council (FRCC) as a utility's ability to energize portions of a blacked-out region using resources independent of an energized interconnection. While Big Bend CT 1 is a black start asset, it is fully depreciated and will be retired in 2015.

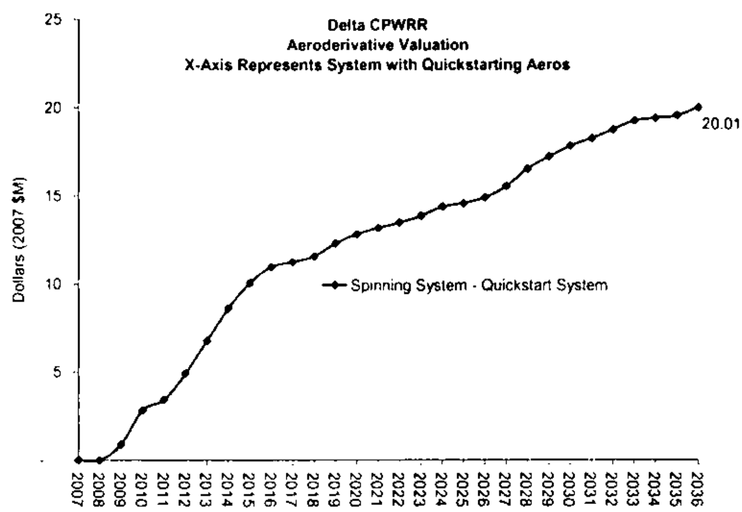
[2] Quick start often refers to ability to reach full load in less than 15 minutes. The Aero CTs generally reach full load in under 10 minutes.

[3] TEC contracts smaller amounts of energy in the form of purchased power and long-term contracts. Likewise, TEC's smallest assets—the Big Bend CTs 1, 2, and 3 (12, 45, and 60 MW) are rarely operated due to high dispatch cost, associated operation and maintenance, and obsolescence.

- Reduces deliverable costs to double-peak loads, where the aeroderivative SCCTs can dispatch to meet short duration heating demand (during winter mornings and/or evenings) more cost effectively than TEC's large, operationally constrained CTs.[4]
- Provides TEC an opportunity to diversify CT technology type and capacity size.

The principal advantages of aeroderivative SCCT technology compared to alternative electrical generation technologies for the BPS SCCT project include:

- Black Start—The aeroderivative SCCTs can be used to energize the BPS in the event of a plant, system, or grid failure.
- Cost Efficient Dispatch—As illustrated in the chart, analysis shows a $20,000,000 (2007) economic benefit to the customer from quick start capability in the TEC system. In sum, the aeroderivative SCCTs proposed in the expansion plan for 2009 and 2010 (base case is X-axis) offer a superior economic option in meeting TEC's operating reserve requirements than with spinning assets alone (change case).[5] The aeroderivative SCCTs can be fully committed in approximately 10 minutes. Without such assets, operating reserve will be met by choosing a less efficient commitment and dispatch plan.



[4] TEC 7FA machines have minimum run times, minimum down times, as well as contractual service agreement (CSA) charges for each start. These operational attributes reduce their ability to serve peak demand cost effectively.

[5] TEC's current operating reserve requirement or "load responsibility" is approximately 88 MW and is expected to increase slightly in 2012. This is TEC's portion of the state's largest generating asset that must be "ready to deliver power promptly."

- Reliability—Tampa Electric projects a 271-MW reserve margin deficit based on the following analysis:

Winter 2010 Incremental Need Year-Over-Year Change	MW
Net available capacity down—lower firm imports	125
Projected native load growth—2.8 percent	120
Reserve margin growth—20 percent of load increase	24
Winter 2010 total year-over-year load deficiency	*269*
Winter 2009 balance—reserve margin shortage	3
Total winter 2010 reliability shortage	**271**

- Diversification of TEC's Generating Asset Base—The 50-MW capacity size fills a void on the system where existing TEC generating assets range from 150 to 475 MW.[6] Likewise, this asset will replace power being purchased mainly for small incremental capacity. Similarly, the aeroderivative SCCTs can serve smaller load blocks at lower cost due to better fuel efficiency at those increments. Specifically, the aeroderivative SCCTs could serve 50 MWs at an approximately 9,500-Btu/kWh heat rate, rather than dispatching a larger TEC CT asset at part load and lower efficiency (i.e., at 28-percent load, a 7FA CT generates approximately 50 MW at more than 14,000 Btu/kWh).[7]

  TEC's current portfolio consists mainly of large-frame CTs (7FAs) that primarily serve intermediate load. When winter months present short double-peaks, the large CT's associated contractual service agreement charges add to their cost. Likewise, the large CTs have associated minimum run times (4 to 7 hours), which usually outlast the 2-hour winter peak. Finally, if a large CT is removed from service for more than 2 hours, it must remain out-of-service for 7 hours, complicating system operators' ability to plan for the

[6] TEC contracts smaller amounts of energy in the form of purchased power and long-term contracts. Likewise, TEC's smallest assets - the Big Bend Combustion Turbines 1,2&3 (12MW, 45MW & 60MW) are rarely operated due to high dispatch cost, associated O&M and obsolescence.

[7] Assumptions: ambient temperature of 55F, Nat. gas., HHV.

second daily winter peak. Conversely, the aeroderivative SCCTs will have no minimum run time, and no minimum down time adding to its operating cost. They can be dispatched more precisely around double-peak demand.

- Diversification of Generation Equipment—TEC is conscientious about diversifying its dependence on any one generation technology. All CTs in TEC's existing fleet are frame-type CTs. It is in TEC's and its stakeholders' interest to keep procurement, installation, and maintenance costs competitive. Therefore, TEC has taken the opportunity to develop experience with a new generation technology, choosing the P&W SwiftPac™ FT8-3® aeroderivative SCCTs in December 2007.

5.3 BACT ANALYSIS FOR NO_X—SCCT

NO_x emissions from combustion sources are formed by one of three mechanisms: thermal, fuel, and prompt. Essentially all SCCT NO_x emissions originate as nitric oxide (NO). NO generated by the SCCT combustion process is subsequently further oxidized downstream of the SCCT or in the atmosphere to the more stable NO_2 molecule.

Thermal NO_x is formed by the high-temperature reaction of nitrogen with oxygen (O_2). 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 by the relatively fast reaction between nitrogen, oxygen, and hydrocarbon radicals. Prompt NO_x formation is important in lower temperature combustion processes but is much less important compared to thermal NO_x formation at the high temperatures in the SCCT.

Fuel NO_x arises from the oxidation of chemically bound nitrogen contained in 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. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content of the fuel. Presently, there are no combustion processes available to control fuel NO_x emissions. For this reason, the gas turbine Subpart GG NSPS, for example, contains an allowance for fuel NO_x. Natural gas contains very little organically bound nitrogen. For natural gas, the primary contributor to NO_x in the exhaust gas is thermal NO_x.

5.3.1 AVAILABLE NO_X CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from CTs 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.
- Dry low-NO_x combustor design.
- XONON®.

Postcombustion Exhaust Gas Treatment Systems:

- Selective noncatalytic reduction (SNCR).
- Nonselective catalytic reduction (NSCR).
- SCR.
- EMx™ (formerly SCONOx™).

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

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.

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

The use of water or steam injection in diffusion flame combustors firing natural gas can typically achieve a NO_x exhaust concentration of 25 ppmvd, corrected to 15-percent oxygen, respectively.

Dry Low-NO_x Combustor Design

A number of CT vendors have developed dry low-NO_x combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner.

Dry low-NO_x combustor technology was developed for natural gas-fired CTs and is not currently available for CTs fired with distillate fuel oil due to the different combustion characteristics of the two fuels.

XONON®

The XONON Cool Combustion® technology, 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 precombustor. 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 precombustor and the flameless combustor catalyst module. Information provided by CESI indicates that the XONON Cool Combustion® technology is capable of achieving CT NO_x exhaust concentrations of 2.5 ppmvd at 15-percent oxygen.

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

Selective Noncatalytic 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 (EPRI's) NO_xOUT and Exxon's Thermal DeNO_x processes. The two processes are similar in that either ammonia (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:

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

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

The NO_xOUT process is similar with the exception that urea is used in place of ammonia. 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 ammonia 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. Exhaust gas temperatures of the BPS SCCTs are too low for this technology.

Nonselective Catalytic Reduction

The NSCR process uses a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3-percent oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines. NSCR has not been applied to CTs.

Selective Catalytic Reduction

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

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

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

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

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO_x molar ratio, catalyst reactivity, catalyst age, 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 ammonia theoretically requires a 1:1 molar ratio. Ammonia/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, ammonia/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions.

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.

As is 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 ammonia will take place resulting in an increase in NO_x emissions. Specially formulated, high-temperature zeolite catalysts have 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.

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multipollutant 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:

$$CO + \frac{1}{2} O_2 \rightarrow CO_2 \qquad (5)$$

$$NO + \frac{1}{2} O_2 \rightarrow NO_2 \quad (6)$$

$$2\ NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3 \quad (7)$$

Carbon dioxide (CO_2) produced by reactions (5) and (7) is released to the atmosphere as part of the CT/HRSG exhaust stream. Water vapor and elemental nitrogen are also 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.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of an HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO_2.

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.

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 combined-cycle CT 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. This facility is no longer operating due to market factors. 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 SCCT located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTs, there are currently no combined-cycle CT units larger than 43 MW that have demonstrated successful application of the EMx™ control technology. In addition, a California study concluded that the capital and annual operating costs for the EMx™ control technology are approximately three times higher than a conventional SCR control system.

5.3.2 TECHNICAL FEASIBILITY AND RANKING

Water or Steam/Diluent Injection

Water or steam injection is a technically feasible technology for aeroderivative SCCTs fired with natural gas.

Dry Low-NO_x Combustor Design

Dry low-NO_x combustor technology is offered by P&W for their aeroderivative SCCTs. However, NO_x emissions estimated by P&W for their dry low-NO_x SCCTs are not any lower than the performance estimated for their water injected units. The P&W dry low-NO_x SCCT units also produce less power compared to the water injected units due to the loss of power augmentation capability associated with water injection. There are also few installations of the P&W aeroderivative SCCT dry low-NO_x systems and, therefore, concerns with long-term reliability. Accordingly, dry low-NO_x represents an inferior NO_x control technology compared to wet injection and is not considered further in this BACT analysis.

XONON™

XONON® is not applicable to the BPS aeroderivative SCCTs because it has not been demonstrated and is not available for this type of CT. In addition, on September 29, 2006, CESI completed the sale of its XONON Cool Combustion® technology and associated gas turbine assets to Kawasaki Heavy Industries, Ltd., marking the CESI's exit from the gas turbine emissions control business. Information obtained from the Kawasaki Heavy Industries, Ltd., Web site indicates that the Xonon Cool Combustion® technology (aka catalysis combustion method) is only available for Kawasaki's small 1.5-MW GPC15 series CT/HRSG cogeneration systems. Accordingly, the XONON Cool Combustion® technology is not considered to be a technically feasible control technology for the BPS SCCTs.

SNCR

SNCR is not technically feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in the BPS SCCT exhaust gas stream (i.e., the SCCT exhaust temperatures will range from 701 to 917 °F).

NSCR

NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent oxygen) environment. Due to high excess air rates, the oxygen content of the BPS SCCT exhaust is greater than 10 percent.

EMx™ (SCONO$_x$)

EMx™ control technology has not been commercially demonstrated on aeroderivative SCCTs. In addition, the EMx™ control technology is not technically feasible because the temperature required for this technology (between 300 to 700°F) is below the approximate 800°F SCCT exhaust gas stream. 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.

SCR

SCR is an established technology for natural gas-fired aeroderivative SCCTs and therefore is technically feasible for the BPS SCCTs.

Accordingly, the NO_x BACT analysis for the BPS SCCT project was confined to wet injection and SCR control technology. Table 5-3 provides a ranking of control efficiencies for the NO_x control technologies discussed previously. The following subsections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.3.3 ENVIRONMENTAL IMPACTS

The installation of SCR technology will cause an increase in back pressure on the SCCTs due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous ammonia from storage to the injection nozzles and generation of steam for ammonia vaporization. An SCR control system for the SCCTs is projected to have a pressure drop across the catalyst bed of approximately 5.6 inches of water. This pressure drop will result in a 1.12-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 6,961,360 kilowatt-hours (kWh) (23,753 million British thermal units [MMBtu]) per year at rated load operation and 2,500 hr/yr per SCCT operation for the eight SCCTs. This energy penalty is equivalent to the use of 23.2 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,024 British thermal units per cubic foot (Btu/ft^3). The lost power generation energy penalty, based on a power cost of $0.030 per kWh, is $208,800 per year.

Application of SCR technology would result in the following adverse environmental impacts:

- Ammonia emissions due to ammonia slip; ammonia emissions are estimated to total 22 tpy for eight SCCTs (at rated load operation for 2,500 hr/yr per SCCT) for a SCR design ammonia slip rate of 5 ppmvd for the eight SCCTs. However, ammonia slip can increase significantly during start-ups, upsets, or failures of the ammonia injection system, or due to catalyst degradation.

Table 5-3. Ranking of Available NO_x Control Technologies—Aeroderivative SCCT

Control Technology	Technically Feasible (Yes/No)	Approximate Control Efficiency* (percent)
Dry low-NO_x or water injection and SCR	Yes	99
SCR	Yes	80 to 90
Dry low-NO_x	Yes	88
Water injection	Yes	88
SNCR	No	Not applicable
NSCR	No	Not applicable
EMx™	No	Not applicable
XONON®	No	Not applicable

*Based on an estimated uncontrolled NO_x exhaust concentration of 200 ppmvd.

Source: ECT, 2008.

In instances where such events have occurred, ammonia exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of ammonia is 20 ppmv, releases of ammonia during upsets or malfunctions have the potential to cause ambient odor problems. Ammonia also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, ammonia 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 ammonia or a high vapor concentration can result in burns or obstructed breathing.

- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of ammonia with sulfur present in the exhaust gases.
- Disposal of spent catalyst that may be considered hazardous due to heavy metal contamination. 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.

5.3.4 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of water injection technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve a NO_x exhaust concentration of 25 ppmvd at 15-percent oxygen. SCR technology was conservatively premised to achieve a NO_x concentration of 2.5 ppmvd at 15-percent oxygen (i.e., 90-percent control efficiency).

The cost impact analysis was conducted using the OAQPS factors previously summarized in Tables 5-1 and 5-2 and project-specific economic factors provided in Table 5-4. Emissions reductions were calculated assuming rated load operation for 2,500 hr/yr at an annual average ambient temperature of 59°F. Tables 5-5 and 5-6 summarize specific capital and annual operating costs for the SCR control system, respectively.

Table 5-4. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0
Control system life	Years	15
SCR catalyst life	Years	4.0
Electricity cost	$/kilowatt-hour	0.030*
Anhydrous ammonia cost (dry basis, delivered)	$/ton	480
Labor costs (base rates)	$/hour	
Operator		25.60
Maintenance		25.60

*Recommended FDEP value.

Sources: TEC, 2008
B&V, 2008.
ECT, 2008.

Table 5-5. Capital Costs for SCR System (Eight SCCTs)

Item	Dollars	EPA Factor
Direct Capital Cost		
Equipment Cost*	16,104,000	EC
Instrumentation	N/A	Included in EC
Freight	N/A	Included in EC
Total Purchased Equipment Cost (PEC)	**$16,104,000**	
Installation Cost		
Foundations and supports	1,288,300	0.08 × PEC
Handling and erection	2,254,600	0.14 × PEC
Electrical	644,200	0.04 × PEC
Piping	322,100	0.02 × PEC
Insulation for ductwork	161,000	0.01 × PEC
Painting	161,000	0.01 × PEC
Total Installation Cost (TIC)	**$4,831,200**	
Total Direct Capital Costs (DCC)	**$20,935,200**	**PEC + TIC**
Indirect Installation Cost		
General facilities	1,046,800	0.05 × DCC
Engineering and home office fees	2,093,500	0.10 × DCC
Process contingency	1,046,800	0.05 × DCC
Total Indirect Installation Cost (IIC)	**$4,187,100**	
Project Contingency (PC)	3,768,300	0.15 x (DCC + IIC)
Total Plant Cost (TPC)	**$28,890,600**	DCC + IIC + PC
Preproduction cost (PPC)	577,800	0.02 × TPC
Initial ammonia inventory cost (OC)	12,436	14 day supply
Total Capital Investment (TCI)	**$29,480,836**	TPC + PPC + OC

*Includes exhaust duct modifications

Sources: P&W, 2008.
ECT, 2008.

Table 5-6. Annual Operating Costs for SCR System (Eight SCCTs)

Item	Dollars	EPA Factor
<u>Direct Cost</u>		
Maintenance labor and materials (ML&M)	442,213	0.015 × TCI
Catalyst replacement cost		
Replacement (materials and labor) (RC)	1,200,000	
Disposal	0	
Total Catalyst Replacement Cost (CRC)	**$1,200,000**	
Capital Recovery Factor (CRF)	0.2952	7.0 percent, 4.0 years
Annualized Catalyst Cost (ACC)	**$354,300**	CRC × CRF
Energy cost	200	OAQPS algorithm
Anhydrous ammonia (AA)	92,500	$480/ton (dry basis)
Energy penalty (EP) Turbine backpressure	208,800	0.20/inch delta P
Emissions fee credit (EFC)	(8,600)	$30/ton NO_x
Total Direct Costs (TDC)	**$1,089,413**	ML&M + ACC + EP+EFC
<u>Indirect Cost</u>		
Capital recovery factor (CRF)	0.1098	7.0 percent, 15 years
Capital recovery	3,105,100	CRF × (TCI-Initial Catalyst)
Total Indirect Cost (TIC)	**$3,105,100**	
Total Annual Cost (TAC)	**$4,194,513**	**TDC + TIC**

Sources: P&W, 2008.
ECT, 2008.

Cost effectiveness for the application of SCR technology to the SCCTs was determined to be $14,564 per ton of NO_x removed. This control cost is considered economically unreasonable. Accordingly, SCR control technology was eliminated due to adverse economic impacts and the next most efficient NO_x control technology (i.e., water injection) was selected as BACT for the BPS SCCT project. Table 5-7 summarizes results of the NO_x BACT analysis.

The NO_x BACT emission limit proposed for the BPS SCCTs is summarized as follows:

- Emission Limit—25.0 ppmvd at 15-percent oxygen.
- Averaging Period—24-hour block average.
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75, either CEMS or Appendix E procedures.

5.4 BACT ANALYSIS FOR NO_X—EMERGENCY GENERATOR DIESEL ENGINES

The BPS SCCT project will include two diesel engine-driven emergency generators each rated at 800 kilowatt. Excluding emergencies, each emergency generator diesel engine will operate no more than 100 hr/yr for routine testing and maintenance purposes. Total estimated PM/PM_{10} emissions for both diesel engines are 1.6 tpy.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad CI engines. Subpart IIII limits the combination of NO_x and nonmethane hydrocarbons emissions to 6.4 grams per kilowatt-hour (g/kWh) for emergency generators purchased in 2007 or later. Emergency diesel engines purchased for the BPS SCCT project will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours is proposed as NO_x BACT for the BPS SCCT project emergency generator diesel engines. NO_x BACT emission limits proposed for each of the BPS SCCT project emergency diesel engines are summarized as follows:

Table 5-7. 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 Impact: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Yes/No)	Environmental Impacts: Adverse Impact (Yes/No)
SCR	25.6	32.0	288.0	29,480,836	4,194,513	14,564	23,753	Yes	Yes
Baseline	256.0	320.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Eight P&W FT8-3® SCCTs, 100-percent load for 2,500 hr/yr per CT natural gas-firing.

Sources: P&W, 2008.
TEC, 2008.
ECT, 2008.

- Emission Limit: Applicable standards of NSPS Subpart IIII.
- Averaging Period: Per NSPS Subpart IIII.
- Compliance Method: Engine manufacturer certification in accordance with NSPS Subpart IIII.
- Annual Operating Hours: 100 hr/yr (excluding emergencies).
- Averaging Period: Calendar year.
- Compliance Method: Monitoring of operating hours using engine run-time meters.

5.5 BACT ANALYSIS FOR PM/PM_{10}—SCCT

PM/PM_{10} emissions resulting from the combustion of natural gas are due to the oxidation of ash and sulfur contained in the fuel. Due to its low ash and sulfur content, combustion of natural gas generates inherently low PM/PM_{10} emissions.

PM is classified by particle size and is defined by the test methods used to measure stack emissions. Filterable PM is measured using EPA Reference Methods 5, 5B, or 17, which capture particles greater than 0.3 micron in size using a filter that is weighed prior to and following the stack test to determine the gain in weight. In Method 5, the filter is located in the sampling train external to the stack and maintained at a temperature of 248°F. A variation of Method 5 is Method 5B, which maintains the filter temperature at 320°F to exclude H_2SO_4 PM. Method 17 places the filter in the stack and therefore collects PM at the prevailing stack temperature. Filterable PM_{10} is measured using either EPA Reference Method 201 or 201A. Both of these test methods collect filterable PM with a nominal aerodynamic diameter of 10 microns or less using an in-stack cyclone and filter system. The filterable PM test methods, commonly referred to as front-half PM, determine the mass of PM that condenses at or above the filter temperature.

EPA also includes condensable PM as a component of PM_{10}. Condensable PM is collected using EPA Reference Method 202 by passing the filtered sample gas stream through a series of chilled water-filled impingers to maintain an impinger outlet sample gas temperature of 68°F or less. Following sampling, the impinger solution is purged with nitrogen and extracted with methylene chloride. The organic and water fractions are then evaporated and the residues weighed to determine the mass of condensable PM. Since the impingers are located in the sampling train downstream of the filter, condensable PM is also referred to as back-half particulate.

In summary, PM includes the filterable portion of PM as measured by EPA Reference Methods 5, 5B, or 17. PM_{10} includes filterable PM less than 10 microns as measured by EPA Reference Method 201 or 201A and condensable PM as measured by EPA Reference Method 202. Since PM_{10} includes condensable particulate and PM does not, PM emission sources will have higher PM_{10} emissions compared to PM. For fossil-fuel combustion sources, PM_{10} emission rates are approximately double that of PM emissions. Accordingly, the distinction between PM and PM_{10} is important when assessing BACT for fossil fuel-fired combustion sources.

5.5.1 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 Collectors

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

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.

Fabric Filters

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM_{10} 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 ($cfm\text{-}ft^2$). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet Scrubbers

Wet scrubbers remove PM/PM_{10} 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/PM_{10} 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 drop 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.

5.5.2 TECHNICAL FEASIBILITY AND RANKING

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 has been applied to SCCTs because exhaust gas PM/PM_{10} concentrations are inherently low. SCCTs operate with high exhaust temperatures and with a significant amount of excess air, which generates large exhaust gas flow rates. The BPS SCCTs will be fired exclusively with natural gas and will generate low PM/PM_{10} emissions in comparison to other fuels due to its low ash and sulfur content. The minor PM/PM_{10} emissions, coupled with a large volume of exhaust gas, produce extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentrations for the BPS SCCTs at baseload and 70°F are approximately 0.002 grain per dry standard cubic foot (gr/dscf). Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5.5.3 EVALUATION OF CONTROL TECHNOLOGIES

The use of clean low-sulfur, low-ash content fuel (e.g., natural gas) is the only feasible control technology for PM/PM_{10} emissions.

5.5.4 PROPOSED BACT PM/PM_{10} EMISSION LIMITATIONS

Recent Florida BACT determinations for SCCTs projects 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. The BPS SCCTs will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The SCCTs will be fired exclusively with pipeline-quality natural gas. The high SCCT combustion temperatures and use of clean natural gas will result in very low PM/PM_{10} emissions.

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 SCCT projects, the use of a clean fuel (e.g., pipeline-quality natural gas) and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. As an indicator of the use of a clean fuels and efficient combustion design and operation, a visible emissions limit of 10-percent opacity is proposed. PM/PM_{10} BACT emission limits proposed for the BPS SCCTs are summarized as follows:

- Emission Limit—10-percent opacity.
- Averaging Period—6-minute block average.
- Compliance Method—EPA Reference Method 9.

5.6 BACT ANALYSIS FOR PM/PM_{10}—EMERGENCY GENERATOR DIESEL ENGINES

The BPS SCCT project will include two diesel engine-driven emergency generators each rated at 800 kilowatts. Excluding emergencies, each emergency generator diesel engine will operate no more than 100 hr/yr for routine testing and maintenance purposes. Total estimated PM/PM_{10} emissions for both diesel engines are less than 0.01 tpy.

The emergency diesel engines will be subject to the applicable emission standards of NSPS Subpart IIII for new nonroad CI engines. Subpart IIII limits PM/PM_{10} emissions to 0.2 g/kWh for emergency generators purchased in 2007 or later. The emergency generator diesel engines purchased for the BPS SCCT project will comply with the applicable emission standards of NSPS Subpart IIII.

Compliance with the stringent NSPS Subpart IIII emission standards and limited annual operating hours is proposed as PM/PM_{10} BACT for the BPS SCCT project emergency generator diesel engines. PM/PM_{10} BACT emission limits proposed for each of the BPS SCCT project emergency diesel engines are summarized as follows:

- Emission Limit: Applicable standards of NSPS Subpart IIII.
- Averaging Period: Per NSPS Subpart IIII.
- Compliance Method: Engine manufacturer certification in accordance with NSPS Subpart IIII.

- Annual Operating Hours: 100 hr/yr (excluding emergencies).
- Averaging Period: Calendar year.
- Compliance Method: Monitoring of operating hours using engine run-time meters.

5.7 SUMMARY OF PROPOSED BACT

Table 5-8 provides a summary of the BACT proposed for the BPS SCCT project, including the emissions limit, averaging period, and compliance method.

Table 5-8. Summary of Proposed BACT

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
SCCTs (per SCCT)	NO_x	24-hour block Calendar year	25.0 ppmvd at 15-percent oxygen 2,500-hr/yr operation	40 CFR 75 Monitoring of operating hours
	PM/PM_{10}	6-minute Calendar year	10-percent opacity 2,500-hr/yr operation	EPA Reference Method 9 Monitoring of operating hours
Black Start Generator Diesel Engines (Per Engine)	NO_x	Not applicable Calendar year	Applicable NSPS Subpart IIII Standard 100-hr/yr operation, excluding emergencies	Engine manufacturer certification Monitoring of operating hours
	PM/PM_{10}	Not applicable Calendar year	Applicable NSPS Subpart IIII Standard 100-hr/yr operation, excluding emergencies	Engine manufacturer certification Monitoring of operating hours

Sources: TEC, 2008.
ECT, 2008.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

As previously noted in Section 3.1, the BPS is located in an area that is designated attainment or unclassifiable for all criteria pollutants. All areas of Florida, with the exception of four PSD Class I areas, are designated as PSD Class II areas. The Florida PSD Class I areas include the Everglades National Park and the Chassahowitzka, St. Marks, and Bradwell Bay NWAs. Accordingly, the BPS and vicinity are classified as a PSD Class II area. This section focuses on the methodology used to determine the BPS SCCT project air quality impacts with respect to the PSD Class II increments and NAAQS. Section 10.0 addresses BPS SCCT project air quality impacts with respect to the PSD Class I areas.

The approach to assessing air quality impacts for a new or modified emission source generally begins by determining the impacts of only the proposed project. If project impacts are below the PSD SILs, then no further analysis is required. The PSD Class II SILs were previously presented in Table 3-4. If the impacts of a proposed project 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 the BPS SCCTs, as described in detail in the following subsections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the BPS SCCT project will have the potential to emit 321.6 tpy of NO_x, 46.8 tpy of CO, 25.0 tpy of PM/PM_{10}, 18.6 tpy of SO_2, 13.5 tpy of VOCs, and 2.1 tpy of H_2SO_4 mist. Table 3-2 previously provided estimated potential annual emission rates for the BPS SCCT project. As shown in that table, potential emissions of NO_x and PM/PM_{10} are each projected to exceed the applicable PSD significant emission rate threshold. Potential emissions for the BPS SCCT project are below the applicable PSD significant emission rate levels for all other PSD regulated pollutants. Accordingly, the BPS SCCT project is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for NO_x and PM/PM_{10}. In accordance with current EPA policy, PM_{10} was used as a surrogate with respect to $PM_{2.5}$ impacts.

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 worst-case operating scenarios for subsequent refined modeling analysis. The refined level consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides improved estimates of source impacts. For the BPS SCCT project air quality analyses, the current version of the refined American Meteorological Society (AMS)/EPA regulatory model (AERMOD) modeling system (Version 07026—January 26, 2007), together with 5 years of hour-by-hour National Weather Service (NWS) meteorology, was used to obtain predictions of both short-term periods (i.e., periods equal to or less than 24 hours) and annual average air quality impacts.

Regulatory agency recommended procedures for conducting air quality impact assessments are contained in the EPA's GAQM. In the November 9, 2005, FR, 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.

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), addenda to the User's Guide, AERMOD Implementation Guides, 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. The CONC option specifies the calculation of concentrations. The BPS is located in Hillsborough County adjacent to Tampa Bay. Based on an analysis of land use in the vicinity of the BPS, the site is considered rural for modeling purposes. Accordingly, 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 equal to the elevation of the stack base, *simple* terrain as lower than the height of the stack top, and *complex* terrain as exceeding the height of the stack being modeled.

Site elevation for the BPS is approximately 10 feet above mean sea level (ft-msl). The SCCT stacks will each have a height of 60 feet (ft) above grade elevation. Accordingly, terrain elevations above approximately 70 ft-msl would be classified as complex terrain. USGS 7.5-minute series topographic maps were examined for terrain features in the BPS impact area. The topography in the vicinity of the BPS is essentially flat with maximum elevations well below the levels that would constitute complex terrain. Based on this examination, terrain in the vicinity of the BPS is classified as ranging from flat to simple terrain for all SCCT stacks.

In accordance with the GAQM recommendations for AERMOD, each modeled receptor was assigned a terrain elevation based on USGS 7.5-minute digital elevation model data and the AERMAP (Version 06341—December 7, 2006) terrain preprocessing program. AERMAP was used in accordance with the latest version of the *User's Guide for the AERMOD Terrain Preprocessor (AERMAP)*, addenda to the User's Guide, and EPA's GAQM.

6.7 BUILDING WAKE EFFECTS

The CAA Amendments 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 heights for the Unit 6 emission sources will comply with the 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).

Heights proposed for the SCCT stacks (60 ft above grade level) are less than the *de minimis* GEP stack height of 65 meters (213 ft) and, therefore, comply with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the BPS SCCT 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 (Version 04274 [September 30, 2004]). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10 to 360 degrees [°]) 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.

Table 6-1 provides dimensions of the BPS buildings/structures evaluated for wake effects. The building/structure dimensions were determined from engineering layouts and specifications. Figure 6-1 depicts the buildings are shown in three-dimension.

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 perimeter of the BPS plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

Table 6-1. Dimensions of SCCT Major Buildings and Structures

Building/Structure	Width (ft)	Length (ft)	Height* (ft)
SwiftPac™ main structure (2 CTs)	12	115	11
SwiftPac ™ CT air inlet filter	12	11	30
SwiftPac™ electric generator silencer	9	11	26

*Height above grade.

Sources: P&W, 2008.
ECT, 2008.

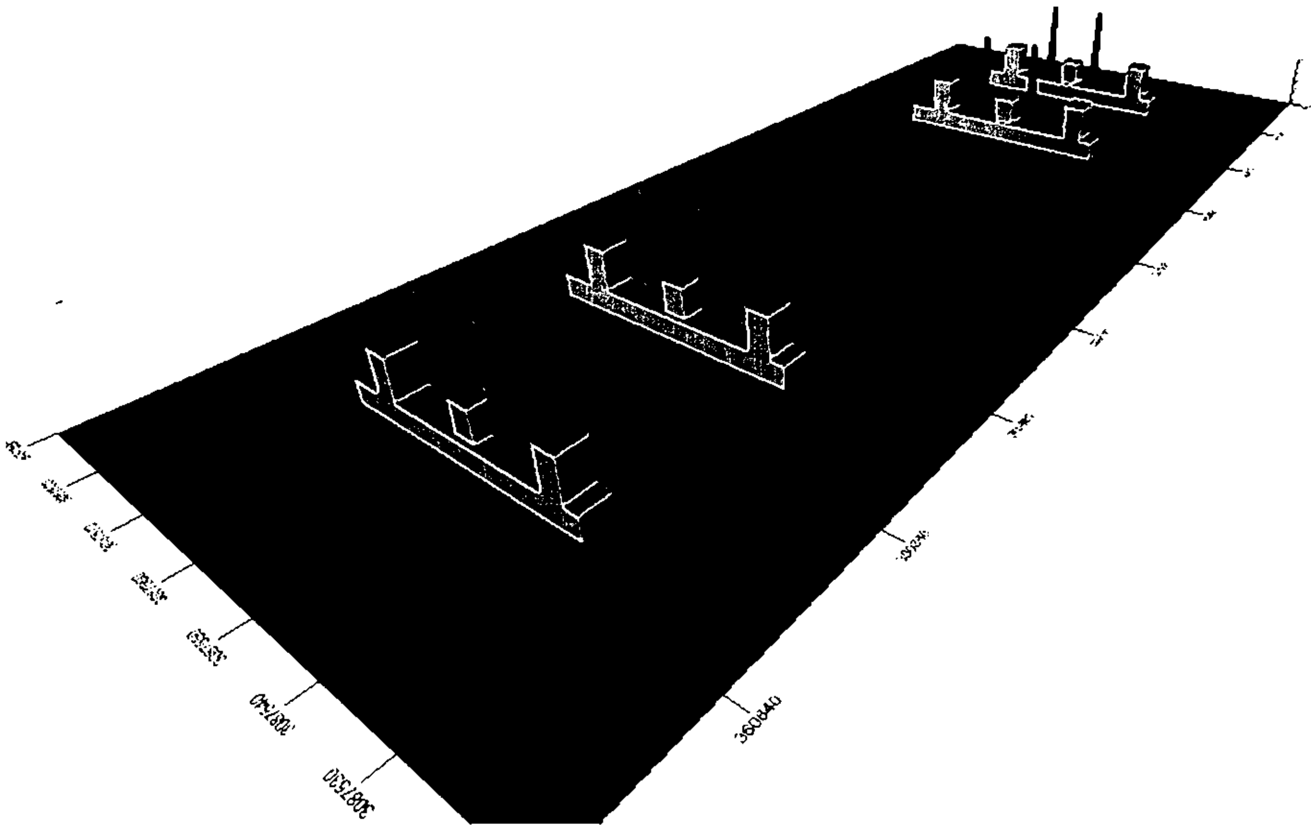


FIGURE 6-1.

SCCT THREE-DIMENSIONAL VIEW

Source: ECT, 2008.

TAMPA ELECTRIC

The receptor grids were formulated consistent with GAQM recommendations. Discrete receptors were placed on the restricted BPS site boundaries. Additional discrete receptors were placed at 10° increments, beginning at 10° on rings at 250 and 500 meters if the specific polar receptor was an ambient air location. Complete rings with receptors located at 10° increments, beginning at 10°, were located at 250-meter increments from 750 to 7,000 meters and at 8,000; 9,000; 10,000; and 12,000 meters. These receptor grids are consistent with prior Gannon/BPS dispersion modeling studies submitted to FDEP.

Figure 6-2 illustrates a graphical representation of the near-field receptor grids (out to a distance of 1,500 meters). Figure 6-3 provides a depiction of the mid- to far-field receptor grids (from 1,500 meters to 12 km).

6.9 METEOROLOGICAL DATA

The AERMET meteorological preprocessing program 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 multi-level data of wind speed, wind direction, and temperature.

AERMET calculates the hourly boundary layer parameters for use by AERMOD, including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, CBL and SBL heights, and surface heat flux. In addition, AERMET passes all observed meteorological parameters to AERMOD including wind direction and speed (at multiple heights, if available), temperature, and if available, measured turbulence. AERMOD uses this information to calculate concentrations in a manner that accounts for a dispersion rate that is a continuous function of meteorology.

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, 5 years (2001 to 2005) of surface and upper air data from the NWS stations (WBAN No. 12842) located at Tampa International

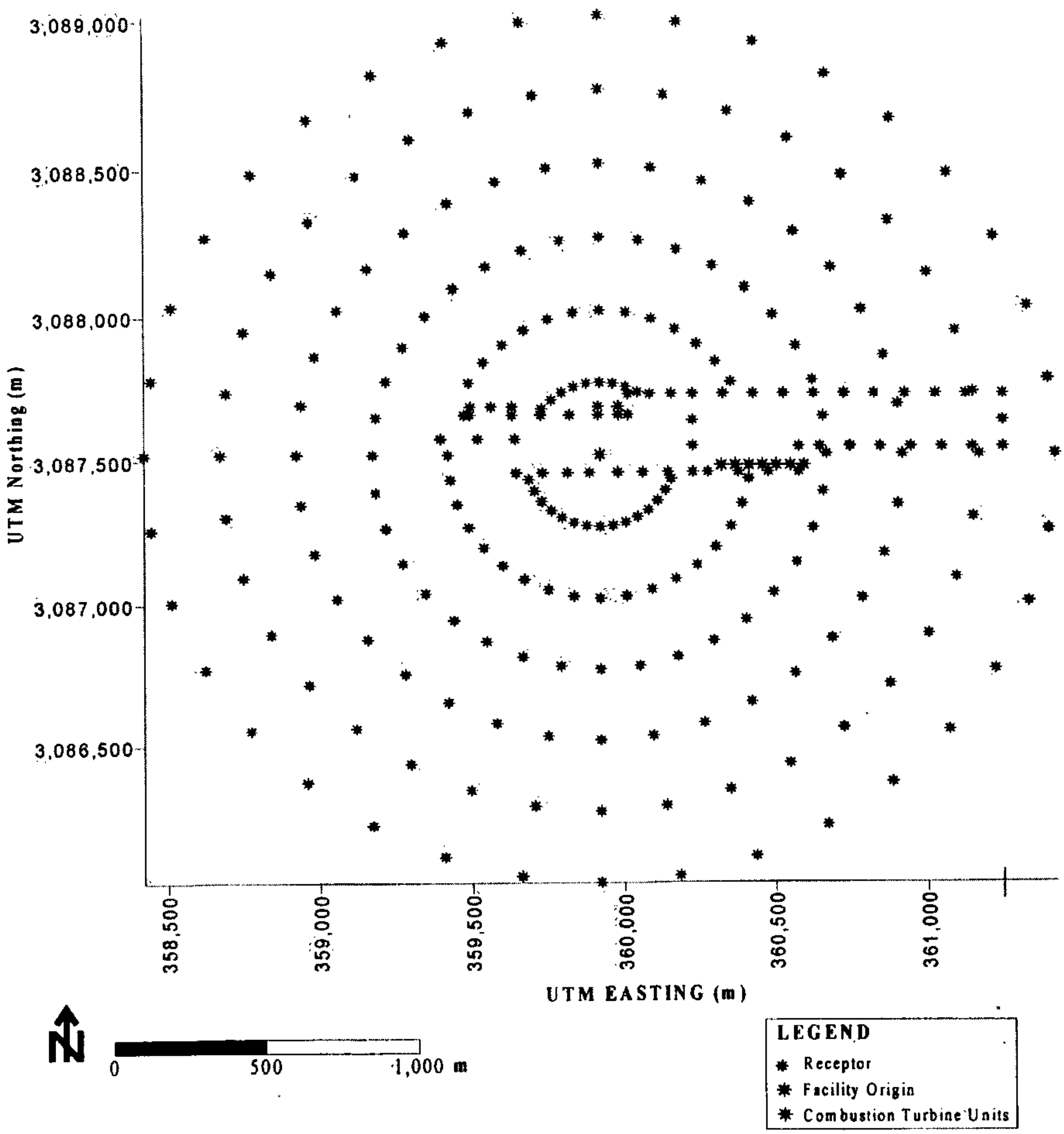


FIGURE 6-2.

SCCT PROJECT NEAR-FIELD RECEPTORS

Source: ECT, 2003.

TAMPA ELECTRIC

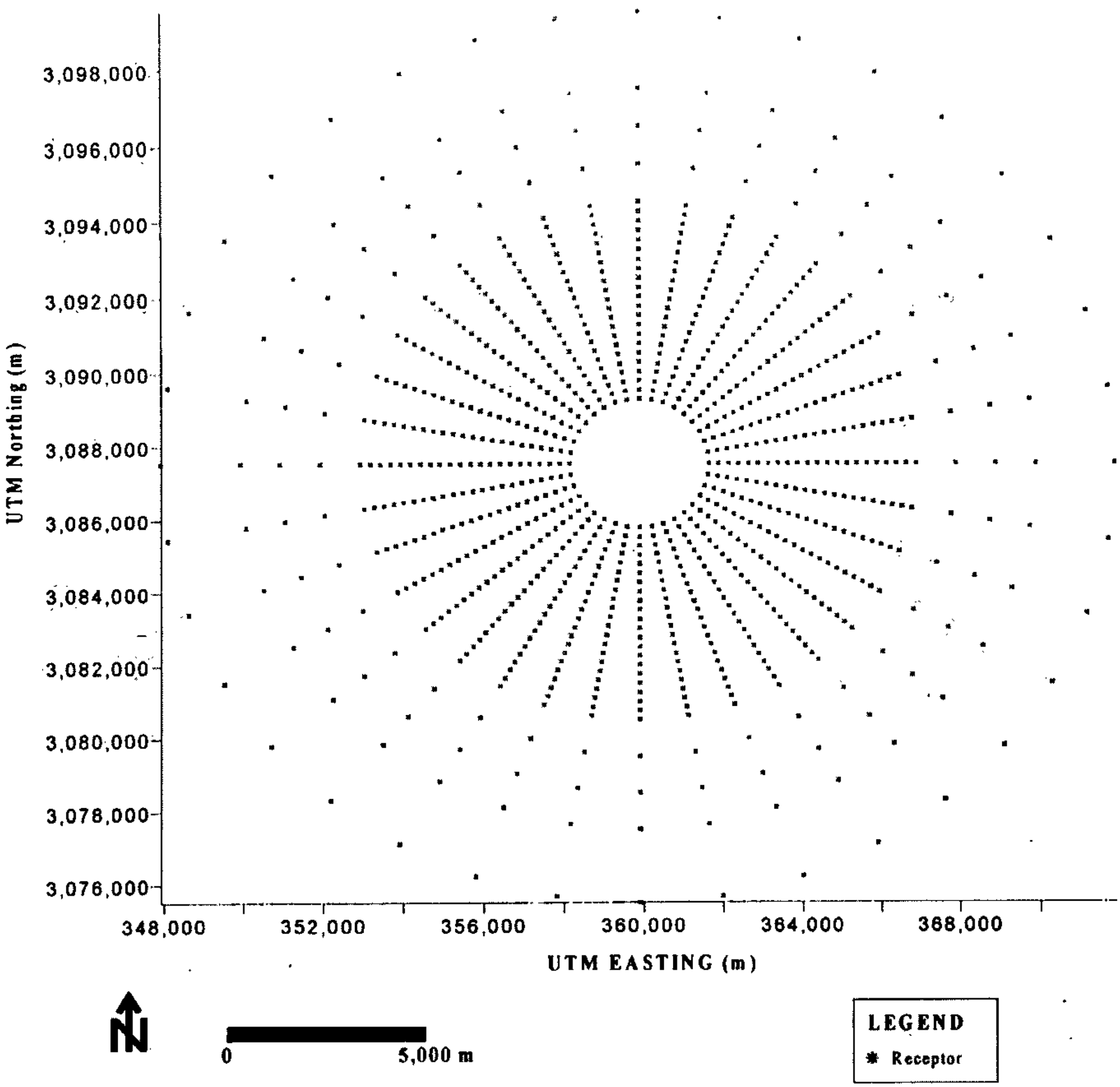


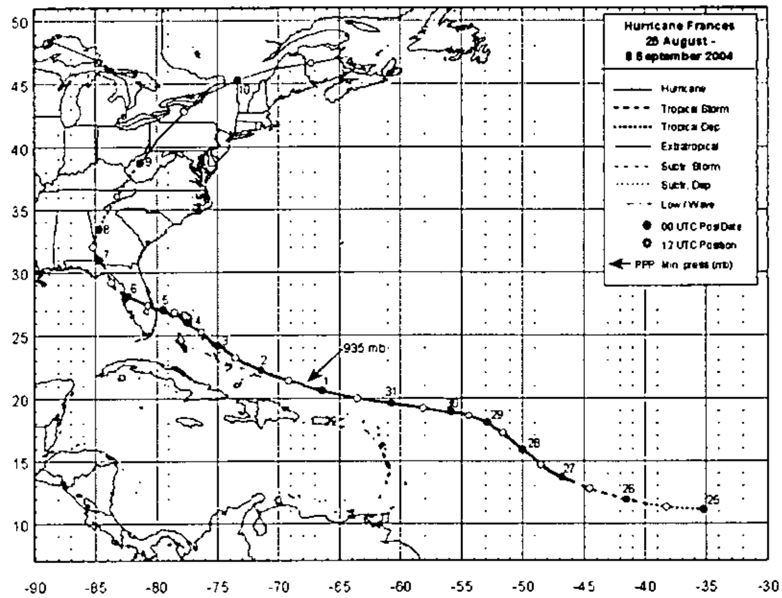
FIGURE 6-3.

SCCT PROJECT MID- AND FAR-FIELD RECEPTOR GRID

Source: ECT, 2003.

TECO
TAMPA ELECTRIC

Airport (TPA) and Ruskin, respectively, were used for the BPS SCCT air quality impact analysis. The AERMET processed meteorological data for these stations was obtained from FDEP. TPA is situated approximately 12 km northwest of the BPS. Both sites are located adjacent to Tampa Bay and have similar land use characteristics.



As will be discussed in Section 7.0, ambient impact analysis results, anomalous model results were obtained for one 24-hour average period: September 5, 2004. Assessment of the weather conditions occurring in the Tampa Bay area on this day indicate that the area was affected by Hurricane Frances. On September 5, 2004, Hurricane Frances made landfall on the east coast of Florida at the southern end of Hutchinson Island as a Category 2 hurricane, crossed the peninsula, and passed directly over the Tampa Bay area before entering the Gulf (see tracking map).

On September 5, 2004, the TIA weather station recorded maximum sustained winds of 44 miles per hour (mph), peak wind gusts of 54 mph, and 5.74 inches of rainfall. Since the extraordinary meteorological conditions that occurred on September 5, 2004, in the Tampa Bay area reflect the influence of Hurricane Frances, the air quality impact analysis for 2004 excluded this day of meteorological data.

6.10 <u>MODELED EMISSION INVENTORY</u>

6.10.1 ON-PROPERTY SOURCES

The modeled on-property emission sources consisted of the eight proposed SCCTs. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the new SCCTs resulted in air quality impacts below the significance impact levels (see Table 3-4) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

During normal operations, the SCCTs will operate over a range of loads (50 to 100 percent) and ambient temperatures (20 to 90°F). A summary of the SCCT operating cases evaluated is provided in Appendix B, Table B-2. Plume dispersion and, therefore, ground-level impacts will be affected by these different operating scenarios since emission rates, exit temperatures, and exhaust gas velocities will change. To simplify the modeling analysis, the pollutant emission rates, stack velocities, and stack temperatures were *enveloped* for the SCCT operating cases to conservatively estimate maximum air quality impacts (i.e., the maximum emission rates and minimum stack velocities and temperatures for all operating cases were used). The specific emission rates and stack data used are summarized as follows:

Fuel Type	Stack Temperature (°F)	Stack Velocity (ft/sec)	NO_x (lb/hr/CT)	PM_{10} (lb/hr/CT)
Natural gas	701.0	66.7	32.0	2.5

Note: ft/sec = foot per second.
lb/hr/CT = pound per hour per CT.

Emissions rates and stack parameters for the proposed SCCTs were previously presented in Tables 2-1 through 2-5. For annual NO_2 air quality impacts, the maximum hourly NO_x emission rate was annualized to reflect the maximum 2,500 annual operating hours per SCCT.

The BPS SCCT project will also include two emergency generator diesel engines. Excluding emergencies, these diesel engines will only operate for approximately 2 hours per week for routine testing and maintenance and therefore were not included in the air quality impact analysis.

6.10.2 OFF-PROPERTY SOURCES

Since the BPS SCCT maximum air quality impacts were below the PSD significant impact levels for all PSD pollutants, a full, multi-source interactive assessment of NAAQS attainment and PSD Class II increment consumption was not required.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive dispersion modeling was conducted to assess the air quality impacts resulting from the BPS SCCT project in accordance with the methodology described in Section 6.0. This section provides the results of the BPS SCCT Class II air quality assessment for NO_2 and PM_{10}. BPS SCCT air quality impacts at distant PSD Class I areas resulting from long-range transport are addressed in Section 10.0.

The BPS SCCTs will operate over a range of loads (50 to 100 percent) and ambient temperatures (approximately 20 to 90°F). As previously discussed in Section 6.0, the SCCT pollutant emission rates, stack velocities, and stack temperatures were *enveloped* for the various operating cases to conservatively estimate maximum air quality impacts (i.e., the maximum emission rates and minimum stack velocities and temperatures for all operating cases were used).

This modeling approach for the BPS SCCTs is conservative (i.e., will overestimate air quality impacts). Maximum impacts will be overestimated since the enveloped modeled SCCT operating cases represent conditions that will not occur (i.e., maximum emission rates at low-load operation and 20°F ambient temperature).

7.2 PSD SIL ANALYSIS RESULTS

Comprehensive dispersion modeling using the EPA AERMOD dispersion model demonstrates that operation of the BPS SCCTs will result in ambient air quality impacts that are below the PSD Class II SILs for all pollutants and all averaging periods. Accordingly, no further modeling analysis with respect to the PSD Class II increments or NAAQS is required.

Detailed BPS SCCT project AERMOD results for each year of meteorology are summarized in Table 7-1 (for annual average NO_2 impacts), Table 7-2 (for annual average PM_{10} impacts), and 7-3 (for 24-hour average PM_{10} impacts). These tables provide maximum BPS SCCT impacts, the locations of these impacts, and relevant regulatory criteria.

Table 7-1. AERMOD Results—Maximum Annual Average NO_2 Impacts

Maximum Annual Impacts	2001	2002	2003	2004	2005
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.75	0.69	0.62	0.61	0.83
Bayside Peaker Emission Rate (g/s/CT)†	1.15	1.15	1.15	1.15	1.15
Tier 1 Impact ($\mu g/m^3$)‡	0.868	0.790	0.709	0.706	0.958
Tier 2 Impact ($\mu g/m^3$)§	0.651	0.593	0.532	0.530	0.718
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	65.1	59.3	53.2	53.0	71.8
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	14.0	14.0	14.0
Exceed PSD de minimis Ambient Impact (Yes/No)	No	No	No	No	No
Receptor UTM Easting (meters)	360,581	360,581	360,863	360,581	360,628
Receptor UTM Northing (meters)	3,087,457	3,087,545	3,087,177	3,087,545	3,087,263
Distance From Bayside CT4B (meters)	308	292	379	292	382
Direction From Bayside CT4B (Vector °)	251	268	182	268	220

*Modeled emission rate of 1.0 g/s for eight CTs.

†Annualized maximum emission rate based on 2,500 hr/yr per CT.

‡Unadjusted AERMOD impact times Bayside Peaker emission rate (assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

§Tier 1 impact times USEPA national default NO_2/NO_x ratio of 0.75.

Source: ECT, 2008.

Table 7-2. AERMOD Results—Maximum Annual Average PM_{10} Impacts

Maximum Annual Impacts	2001	2002	2003	2004	2005
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.75	0.69	0.62	0.61	0.83
Bayside Peaker Emission Rate (g/s/CT)†	0.090	0.090	0.090	0.090	0.090
AdjustedAERMOD Impact ($\mu g/m^3$)‡	0.068	0.062	0.055	0.055	0.075
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	6.8	6.2	5.5	5.5	7.5
Receptor UTM Easting (meters)	360,581	360,581	360,863	360,581	360,628
Receptor UTM Northing (meters)	3,087,457	3,087,545	3,087,177	3,087,545	3,087,263
Distance From Bayside CT4B (meters)	308	292	379	292	382
Direction From Bayside CT4B (Vector °)	251	268	182	268	220

*Modeled emission rate of 1.0 g/s for eight CTs.
†Annualized maximum emission rate based on 2,500 hr/yr per CT.
‡Unadjusted AERMOD impact times Bayside Peaker emission rate.

Source: ECT, 2008.

Table 7-3. AERMOD Results—Maximum 24-Hour Average PM_{10} Impacts

Maximum 24-Hour Impacts	2001	2002	2003	2004	2005
AERMOD Impact (µg/m³)*	12.85	9.29	10.54	18.61	14.37
AERMOD Impact (µg/m³)†				13.50	
Bayside Peaker Emission Rate (g/s/CT)	0.32	0.32	0.32	0.32	0.32
AdjustedAERMOD Impact (µg/m³)‡	4.05	2.93	3.32	4.25	4.53
PSD Significant Impact (µg/m³)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	81.0	58.5	66.4	85.1	90.6
PSD *de minimis* Ambient Impact Threshold (µg/m³)	10.0	10.0	10.0	10.0	10.0
Exceed PSD de minimis Ambient Impact (Yes/No)	No	No	No	No	No
Receptor UTM Easting (meters)	361,154	360,431	360,863	360,908	360,908
Receptor UTM Northing (meters)	3,087,302	3,087,728	3,087,177	3,087,345	3,087,345
Distance From Bayside CT4B (meters)	379	474	379	214	214
Direction From Bayside CT4B (Vector °)	132	291	182	171	171
Date of Maximum Impact	03/05/01	04/08/02	11/29/03	09/26/04	10/24/05

*Modeled emission rate of 1.0 g/s for eight CTs.

†Modeled emission rate of 1.0 g/s for eight CTs. excluding September 5. 2004 (Hurricane Francis) (see Section 6.9).

‡Unadjusted AERMOD impact times Bayside Peaker emission rate.

Source: ECT. 2008.

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Maximum BPS SCCT project air quality impacts using AERMOD and the identified worst-case operating cases are summarized in Table 7-4. The AERMOD results presented in Table 7-4 demonstrate that BPS SCCT project air quality impacts, for all modeled pollutants and averaging periods, will be below the PSD SILs previously shown in Table 3-4. As previously noted, the Class II impact results overestimate actual air quality impacts due to the conservative modeling approach taken

7.3 OZONE IMPACTS

Ozone is formed in a complex series of chemical reactions involving primarily NO_x and VOCs during warm ambient temperatures in the presence of sunlight. Since ozone is formed from precursor pollutants, assessment of ambient ozone impacts is typically conducted on a regional basis using resource-intensive models such as the EPA Community Multiscale Air Quality model. Currently, all areas of Florida are attaining the 8-hour ozone AAQS.

BPS SCCT project estimated potential NO_x and VOC emissions are 321.6 and 13.5 tpy, respectively. These annual emission rates are relatively minor in comparison to regional emissions. For example, Hillsborough County NO_x and VOC emissions in 2001 were 103,401 and 53,740 tons, respectively, based on data obtained from the EPA AirData Web site. Hillsborough County currently has monitored ambient ozone levels below the ozone AAQS.

Ambient ozone levels in Hillsborough County are primarily due to transportation emission sources. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Florida has improved over the last 5 years due to improvements in motor vehicle emission rates. Continued reductions in average motor fleet emissions would be expected to further improve ozone air quality. In addition, the CAIR will result in significant actual reductions in existing power plant NO_x emissions throughout Florida. During Phase 1 (2009 through 2014) of the CAIR program, EPA estimates that actual Florida power plant NO_x emissions during the 5-month ozone season (May through September) will be reduced from 119,000 tons (in 2003) to 33,000 tons—a reduction of

Table 7-4. AERMOD Results Summary—Bayside SCCT Project

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	PSD Class II Significant Impact ($\mu g/m^3$)	Percent of Significant Impact ($\mu g/m^3$)
NO_2	Annual	0.72	1.0	71.8
PM/PM_{10}	Annual	0.075	1.0	7.5
	24-Hour	4.5	5.0	90.6

Source: ECT, 2008.

86,000 tons. In comparison, the BPS SCCT project estimated ozone season NO_x emissions will be only approximately 134 tons. The CAIR program power plant emission reductions will occur throughout Florida, including areas in the vicinity of the BPS, and will occur prior to the commencement of operation of the SCCT project. As an example, TEC has recently retrofitted a selective catalytic reduction (SCR) emission control systems to its existing Big Bend Station Unit 4 that will result in an estimated annual reduction in actual NO_x emissions of roughly 2,000 tons, which is approximately six times higher than the estimated BPS SCCT project NO_x emissions. TEC also plans to install SCR controls on the remaining Big Bend Station Units 1 through 3. Overall, TEC has reduced actual NO_x emissions from its generating stations by approximately 40,000 tons per year since 2002 with the majority of these reductions occurring in the Tampa Bay area.

In summary, the relatively minor NO_x and VOC emissions associated with the BPS SCCT project will not significantly impact ambient ozone levels in Hillsborough County or other areas in Florida. Hillsborough County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

There are 14 ambient air quality monitor stations located in Hillsborough County. To assess air quality representative of the BPS site, data from the nearest monitoring stations to the BPS were reviewed.

The nearest ambient air quality monitoring station is located at the CWU Building on U.S. Highway 41 in Gibsonton, approximately 1.8 km southeast of the BPS. This station monitors the ambient air for PM_{10}. The nearest ambient air quality monitoring station that monitors for $PM_{2.5}$ is located at 3910 Morrison Avenue in Tampa, approximately 10 km west of the BPS. The nearest ambient air quality monitoring station that monitors for SO_2 is located at 5012 Causeway Boulevard in Tampa, approximately 2.0 km northeast of the BPS. The nearest ambient air quality monitoring station that monitors for 1- and 8-hour average ozone is located on Davis Island in Tampa, approximately 4.7 km northwest of the BPS. The nearest NO_2 ambient air quality monitoring station is located at Simmons Park, Tampa, approximately 19 km south of the BPS. The nearest CO ambient air quality monitoring station is located at 4702 Central Avenue in Tampa, approximately 10 km northwest of the BPS. The nearest ambient air quality monitoring station for lead is situated at the Patent Scaffolding facility in Tampa, Hillsborough County, approximately 7.3 km north of the BPS.

Data for these monitoring stations for calendar years 2002 through 2006 are provided in Table 8-1. As shown in Table 8-1, all of the criteria pollutant ambient data collected at these stations are below the applicable NAAQS. Hillsborough County is currently classified attainment for all criteria pollutants.

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 two PSD pollutants will be emitted from the BPS SCCT

Table 8-1. Hillsborough County Ambient Air Quality Data Summary—2002 through 2006 (Page 1 of 3)

Pollutant	Site Location City	Site Name	FDEP Site ID	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration ($\mu g/m^3$) 1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
PM_{10}	Tampa	5012 Causeway Boulevard	057-0095	2.0	34	2002	24-hour	168	48	39		150[a]	32.0
						2003	24-hour	361	69	61		150[a]	46.0
						2004	24-hour	353	64	63		150[a]	42.7
						2005	24-hour	365	76	69		150[a]	50.7
						2006	24-hour	365	90	80		150[a]	60.0
						2002	Annual	168			22	50[b]	44.0
						2003	Annual	361			26	50[b]	52.0
						2004	Annual	353			27	50[b]	54.0
						2005	Annual	365			27	50[b]	54.0
						2006	Annual	365			29	50[b]	58.0
PM_{10}	Gibsonton	U.S. Highway 41, CWU Building	057-0066	1.8	143	2002	24-hour	61	59	55		150[a]	39.3
						2003	24-hour	58	66	64		150[a]	44.0
						2004	24-hour	60	51	43		150[a]	34.0
						2005	24-hour	61	72	63		150[a]	48.0
						2006	24-hour	61	75	67		150[a]	50.0
						2002	Annual	61			25	50[b]	50.0
						2003	Annual	58			27	50[b]	54.0
						2004	Annual	60			25	50[b]	50.0
						2005	Annual	61			28	50[b]	56.0
						2006	Annual	61			33	50[b]	66.0
$PM_{2.5}$	Tampa	3910 Morroson Avenue	057-0030	10	287	2002	24-hour	336	25	24		65[a]	38.5
						2003	24-hour	341	24	23		65[a]	36.9
						2004	24-hour	344	35	30		65[a]	53.8
						2005	24-hour	348	44	43		65[a]	67.7
						2006	24-hour	337	24	23		65[a]	36.9
						2002	Annual	336			10.7	15[b]	71.3
						2003	Annual	341			10.4	15[b]	69.3
						2004	Annual	344			11.3	15[b]	75.3
						2005	Annual	348			11.1	15[b]	74.0
						2006	Annual	337			9.9	15[b]	66.0

Table 8-1. Hillsborough County Ambient Air Quality Data Summary—2002 through 2006 (Page 2 of 3)

Pollutant	Site Location City	Site Name	FDEP Site ID	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (μg/m³) 1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
SO_2	Tampa	5012 Causeway Boulevard	057-0095	2.0	34	2002	3-hour	8,477	282	248		1,300[c]	21.7
						2003	3-hour	8,697	196	185		1,300[c]	15.1
						2004	3-hour	8,643	52	44		1,300[c]	4.0
						2005	3-hour	8,650	219	170		1,300[c]	16.9
						2006	3-hour	8,716	73	50		1,300[c]	5.6
						2002	24-hour	8,477	50	47		365[c]	13.6
						2003	24-hour	8,697	47	31		365[c]	12.9
						2004	24-hour	8,643	10	10		365[c]	2.9
						2005	24-hour	8,650	55	31		365[c]	15.0
						2006	24-hour	8,716	16	13		365[c]	4.3
SO_2	Tampa	5012 Causeway Boulevard	057-0095	2.0	34	2002	Annual	8,477			10.4	80[b]	13.1
						2003	Annual	8,697			7.8	80[b]	9.8
						2004	Annual	8,643			5.2	80[b]	6.5
						2005	Annual	8,650			5.2	80[b]	6.5
						2006	Annual	8,716			2.6	80[b]	3.3
NO_2	Tampa	Simmons Park	057-0081	19	196	2002	Annual	8,692			13.1	100[b]	13.1
						2003	Annual	8,444			13.1	100[b]	13.1
						2004	Annual	8,171			11.3	100[b]	11.3
						2005	Annual	8,642			11.3	100[b]	11.3
						2006	Annual	8,549			11.3	100[b]	11.3
CO	Tampa	4702 Central Avenue	057-1070	10	336	2002	1-hour	8,723	6,057	6,057		40,000[c]	15.1
						2003	1-hour	8,459	8,343	6,514		40,000[c]	20.9
						2004	1-hour	8,656	5,143	5,029		40,000[c]	12.9
						2005	1-hour	8,636	4,800	4,571		40,000[c]	12.0
						2006	1-hour	8,721	4,686	4,571		40,000[c]	11.7
						2002	8-hour	8,723	5,143	4,343		10,000[c]	51.4
						2003	8-hour	8,459	4,114	3,771		10,000[c]	41.1
						2004	8-hour	8,656	3,314	2,857		10,000[c]	33.1
						2005	8-hour	8,636	4,000	3,429		10,000[c]	40.0
						2006	8-hour	8,721	3,314	3,314		10,000[c]	33.1

Table 8-1. Hillsborough County Ambient Air Quality Data Summary—2002 through 2006 (Page 3 of 3)

Pollutant	Site Location City	Site Name	FDEP Site ID	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration ($\mu g/m^3$) 1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
Lead	Tampa	Patent Scaffolding	057-1073	7.3	28	2002	quarter	59	0.41	0.23		1.5[b]	27.3
						2003	quarter	58	0.25	0.25		1.5[b]	16.7
						2004	quarter	56	0.23	0.19		1.5[b]	15.3
						2005	quarter	61	0.29	0.17		1.5[b]	19.3
						2006	quarter	58	0.27	0.24		1.5[b]	18.0
									[ppm]			[ppm]	
O_3	Tampa	Davis Island	057-1035	4.7	300	2002	1-hour*	240	0.104			0.12[d]	86.7
						2003	1-hour*	244	0.098			0.12[d]	81.7
						2004	1-hour*	241	0.098			0.12[d]	81.7
						2005	1-hour*	243	0.102			0.12[d]	85.0
						2006	1-hour*	245	0.102			0.12[d]	85.0
									[ppm]			[ppm]	
						2002	8-hour†	238	0.076			0.08[e]	89.5
						2003	8-hour†	244	0.073			0.08[e]	86.0
						2004	8-hour†	240	0.070			0.08[e]	82.4
						2005	8-hour†	242	0.074			0.08[e]	87.2
						2006	8-hour†	245	0.076			0.08[e]	89.5

[a] 98th percentile.
[b] Arithmetic mean.
[c] 2nd high.
[d] 4th highest day with hourly value exceeding standard over a 3-year period.
[e] 4th highest daily 8-hour concentation averaged over a 3-year period.

*4th highest 1-hour concentrations over a 3-year period.
†4th highest 8-hour concentration averaged over a 3-year period.

Sources: FDEP, 2008.
EPA, 2008.
ECT, 2008.

project in excess of their respective significant emission rates, preconstruction monitoring is required. However, Rule 62-212.400(3)(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 the BPS SCCT project.

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 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 4.5 micrograms per cubic meter ($\mu g/m^3$). This concentration is below the 24-hour average PM_{10} *de minimis* ambient impact level of 10 $\mu g/m^3$. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the FDEP PSD regulations.

8.2.2 NO_2

The maximum annual NO_2 impact was predicted to be 0.72 $\mu g/m^3$. This concentration is below the annual average NO_2 *de minimis* ambient impact level of 14 $\mu g/m^3$. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

8.2.3 OZONE

Preconstruction monitoring for ozone is required if potential NO_x or VOC emissions from a project subject to PSD review exceed 100 tpy. The BPS SCCT project potential NO_x and VOC emissions are 321.6 and 13.5 tpy, respectively. Since the BPS SCCT project potential NO_x emissions exceed the 100-tpy threshold, preconstruction monitoring is required for ozone.

However, in accordance with EPA guidance, representative current quality-assured ambient data collected at an ambient monitoring site in the general vicinity of the BPS can be used to satisfy the PSD preconstruction ambient air monitoring requirements. The Hillsborough County Environmental Protection Commission (HCEPC) maintains an extensive network of ozone ambient air quality monitoring stations in the Tampa Bay area. The nearest ozone monitoring station is located on Davis Island, approximately 4.7 km northwest of the BPS. Since ozone is a regional air pollutant, this monitoring station provides ozone data representative of the BPS site and is used to satisfy the PSD preconstruction ambient air monitoring requirements. The ambient ozone data collected by HCEPC at Davis Island (Site 057-1035) is representative ambient air data for the BPS site and, therefore, onsite preconstruction ambient air monitoring for ozone is not required.

9.0 ADDITIONAL IMPACT ANALYSIS

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 subsections.

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 the BPS SCCT project will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The BPS SCCT project is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. The BPS SCCT project is projected to generate an average of 100 new jobs during construction. Following construction, the BPS SCCT project will employ approximately 20 fulltime employees. This number of new personnel will not significantly affect growth in the area. The increase in natural gas demand due to the operation of the BPS SCCT project 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 Hillsborough County has increased by approximately 80 percent between 1980 and 2006. The Hillsborough County population, as of July 2006, was 1,157,738, of which Tampa contributed 332,888. The population increased in the city of Tampa by approximately 1.5 percent per year from 2000 to 2006, which is significantly less than the 2.7-percent increase per year seen from 1980 to 2000.

The Tampa area is home to several major businesses and some industries, while remaining to be a major tourist destination. A major theme park (Busch Gardens), several museums, and a comfortable winter climate attract many visitors year round. Tampa has changed more from an industrial sea port to a city that depends on service, retail, finance, and real estate to support their economy. In 1997, Tampa had approximately $16 billion in wholesale trade sales.

Many Tampa industries have either shifted their interests or greatly reduced their emissions of criteria pollutants over the past 30 years, which has improved the air quality in the area. Although Hillsborough County was nonattainment for ozone prior to 1996, since then it has been in attainment for ozone and all other criteria pollutants.

The major air quality impact of the growth that has occurred in the Tampa 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 has resulted in improvements in the area's air quality. Although the Tampa Bay 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 Tampa area has not deteriorated since 1977. As discussed in Section 7.0, the relatively minor emissions associated with the BPS SCCT project will not cause any significant air quality impacts.

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the BPS due to SCCT project operations will be below the applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the BPS are anticipated. The following subsections discuss potential impacts on the nearest Class I area, the Chassahowitzka NWA.

9.2.1 IMPACTS ON SOILS

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

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

9.2.2 IMPACTS ON VEGETATION

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

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of the BPS due to SCCT project operations would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at Chassahowitzka NWA due to emissions from the BPS SCCT project will be far less. The potential for damage at the Chassahowitzka NWA could, therefore, be considered negligible given the much lower air pollution impacts predicted at Chassahowitzka NWA relative to the immediate BPS plant vicinity and the absence of any plant species at Chassahowitzka NWA that would be especially sensitive to the minimal predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

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

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

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

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

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

In conclusion, it is unlikely the projected air emission levels from the BPS SCCT project will have any measurable direct or indirect effects on wildlife using the Chassahowitzka NWA.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the BPS SCCT project. Visible emissions from the SCCTs will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the SCCTs unit will be low due to the exclusive use of low-sulfur, pipeline-quality natural gas. The BPS SCCT project will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACT RESULTS

10.1 OVERVIEW

Comprehensive refined modeling was conducted to assess BPS SCCT project Class I area air quality impacts in accordance with EPA, Federal Land Managers (FLM), and FDEP modeling guidance. This section provides the results of the BPS SCCT project air quality assessment with respect to long-range transport impacts at the Chassahowitzka NWA PSD Class I area. BPS SCCT project air quality impacts in the vicinity of the project site were previously addressed in Section 7.0.

PSD Class I areas located within 300 km of the BPS SCCT project include a portion of the Okefenokee NWA in Georgia and the Chassahowitzka and St. Marks NWAs and a portion of the Everglades National Park in Florida. The BPS is located 295 km (183 miles) south of the Okefenokee NWA, 285 km (177 miles) southeast of the St. Marks NWA, and 244 km (151 miles) northwest of the Everglades National Park. The nearest PSD Class I area is the Chassahowitzka NWA, situated approximately 80 km (50 miles) north of the BPS. Since the other PSD Class I areas are located at much greater distances from the BPS, the Class I impact analysis was confined to the Chassahowitzka NWA. The locations of the Class I areas located within 300 km of the BPS are shown on Figure 10-1.

10.2 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the BPS SCCT project will have insignificant air quality impacts for all modeled PSD pollutants and all averaging periods. Accordingly, a multi-source cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2 and PM_{10} was not required.

In addition, BPS SCCT project maximum regional haze impacts and sulfur and nitrogen deposition rates will be below the relevant FLM screening level guidelines. Therefore, further analysis of these air quality-related values (AQRVs) was not required.

M:\acad\071286\class1Location map.mxd

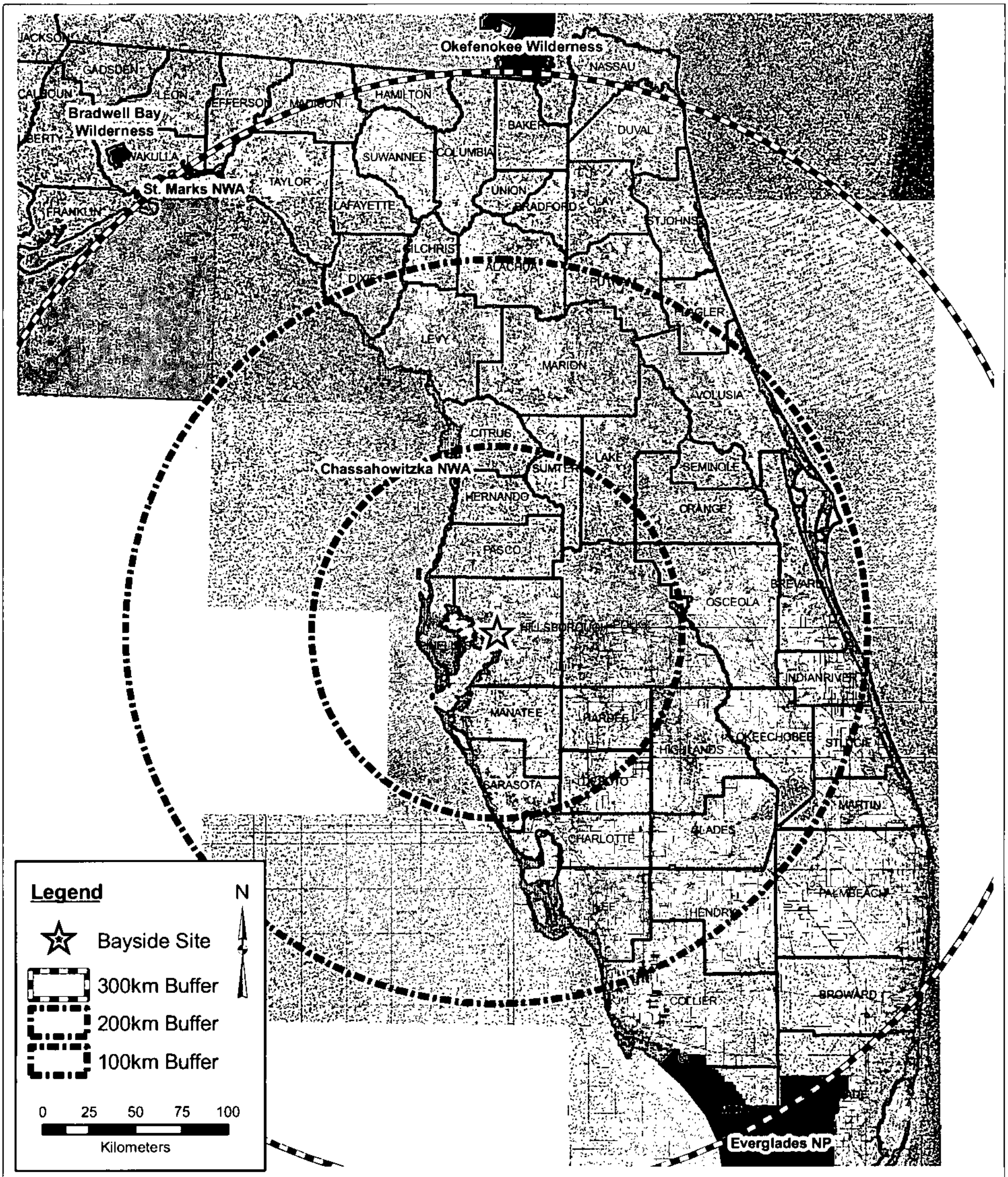

FIGURE 10-1.
LOCATION OF CLASS 1 AREAS

Sources: FGDL, 2003; ECT, 2008.

10.3 GENERAL APPROACH

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, the *Federal Land Managers' Air Quality-Related Values Workgroup (FLAG) Phase I Report*, and EPA's *Guideline on Air Quality Models*.

The CALPUFF model was employed in a refined mode using 3 years (2001 through 2003) of 4-km resolution CALMET data and Class I area receptor grids as recommended by the National Park Service (NPS). The CALPUFF suite of programs, including the POSTUTIL and CALPOST postprocessing programs, was employed to develop estimates of BPS SCCT project impacts on the Chassahowitzka NWA for PSD increments, regional haze, and deposition.

10.4 MODEL SELECTION AND USE

Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction, nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as AERMOD, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

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

The IWAQM work plan indicates that a phased approach would be taken with respect to the implementation of recommendations for long-range transport modeling. In Phase 1, the IWAQM would review current EPA modeling guidance and issue an interim modeling approach applicable to projects undergoing permit review. For Phase 2, a review would be made of other available long-range transport models and recommendations developed for the most appropriate modeling techniques.

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments. The Phase 2 recommendations, issued in December 1998, are contained in the IWAQM Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts. Additional FLM guidance with respect to the assessment of visibility and deposition impacts is provided in the FLAG Phase I Report dated December 2000. The Phase 2 IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. In April 2003, EPA designated the CALPUFF model as a preferred model (i.e., a model listed in Appendices A to W of 40 CFR 51, Summaries of Preferred Air Quality Models) for use in assessing the long-range transport of air pollutants.

The EPA GAQM indicates that the CALPUFF modeling system is appropriate for long-range transport (source-receptor distances of 50 to several hundred kilometers) of emissions from point, volume, area, and line sources. All the receptors at the Chassahowitzka NWA Class I area are situated greater than 50 km from the BPS SCCT project.

The EPA-approved version of the CALPUFF modeling suite was used for the BPS SCCT project Class I area impact assessments. The EPA-approved CALPUFF modeling suite is comprised of the following programs:

- CALMET Version 5.8 Level: 070623.
- CALPUFF Version: 5.8 Level: 070623.
- POSTUTIL Version: 1.56 Level: 070627.
- CALPOST Version: 5.6394 Level: 070622.

These programs were used to assess PSD Class I increments, regional haze, and nitrogen and sulfur deposition impacts.

The CALPUFF modeling system consists of three main components: CALMET, CALPUFF, and CALPOST. Each of these components is described in the following subsections.

10.4.1 CALMET

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

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

- Penn State/National Center for Atmospheric Research mesoscale model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed).
- Surface station weather data (wind speed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code).
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and wind speed at each sounding).
- Surface station precipitation data (precipitation rates).
- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, wind speed, and wind direction).
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux).

Further technical discussion of the CALMET model can be found in Chapter 2 of the User's Guide for the CALMET meteorological model dated January 2000.

The Visibility Improvement State and Tribal Association of the Southeast (VISTAS) has developed a 3-year (2001 through 2003) CALMET dataset for a fine, 4-km, subregional domain that covers all of Florida and the adjacent Class I areas of interest to Florida. The VISTAS 2001 to 2003 meteorological data was recently reprocessed by the U.S. Fish and Wildlife Service using the current EPA regulatory version of CALMET (i.e., Version 5.8, Level: 070623). This reprocessed fine-grid CALMET dataset (containing more than 250 gigabytes of data) was obtained from FDEP and was used in the BPS SCCT project Class I impact assessments.

10.4.2 CALPUFF

CALPUFF is a transport and puff model that advects puffs of material from an emission source. These puffs undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also use nongridded meteorological data similar to that used by a steady-state dispersion model such as AERMOD. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models. Further technical discussion of the CALPUFF model can be found in Chapter 2 of the User's Guide for the CALPUFF Model dated January 2000.

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

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

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Unit 6 Class I area impact assessments conform to the recommendations contained in the IWAQM Phase 2 report and EPA's GAQM. Key CALPUFF model options selected for the BPS SCCT project Class I impact assessments are listed:

- CALPUFF domain configured to include the BPS SCCT project emission sources and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.
- Class I receptors as defined by NPS.
- Modeling of 11 species (SO_2, sulfuric acid [SO_4], NO_x, nitric acid, nitrate, $PM_{1.0}$, $PM_{0.25}$, $PM_{0.20}$, $PM_{0.15}$, $PM_{0.10}$, and $PM_{0.05}$).
- Use of the MESOPUFF II chemical mechanism module.
- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.
- 2001 through 2003 ozone data from CASTNet and AIRS stations.
- Background ammonia concentration of 0.5 part per billion.
- Integrated puff sampling methodology.
- No consideration of building downwash.

The PM fractions indicated previously address the PM size distribution expected for the BPS SCCTs firing natural gas. The Class I impacts for the PM_{10} fractions, together with primary sulfate impacts, were summed to obtain total PM_{10} impacts.

10.4.3 POSTUTIL

POSTUTIL is a postprocessing program used to process the concentrations generated by CALPUFF. POSTUTIL was used to develop visibility PM component emission rates (i.e., elemental and organic carbon PM fractions), consolidate the PM_{10} impacts (i.e., impacts due to PM_{10} fractions and primary sulfate), consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes.

10.4.4 CALPOST

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

For visibility assessments, background conditions were estimated using natural background data (i.e., absent anthropogenic influences). The CALPOST program was then used to compute background extinction coefficients using the natural background data and the IWAQM recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the BPS SCCT project Class I impact assessments conform to the recommendations contained in the FLAG Phase I Report.

10.5 RECEPTOR GRIDS

The BPS SCCT project Class I area receptor grid included the Chassahowitzka NWA (113 discrete receptors) receptors identified by NPS for this Class I area. The Class I receptor locations, which are provided by NPS in geographic (latitude and longitude) coordinates, were converted to Lambert Conformal Conic coordinates consistent with the VISTAS fine 4-km CALMET grid parameters (i.e., two matching parallels, latitude/longitude of the projection origin, and coordinate datum) using the NPS Class I Areas Conversion program.

10.6 MODELED EMISSION SOURCES

BPS SCCT project modeled emission sources included the eight SCCTs. The SCCT project emergency generator diesel engines will operate intermittently (approximately

2 hours per week for routine testing and maintenance) and will have a low release height. Accordingly, these emission sources will have negligible impacts at the distant Chassahowitzka NWA Class I area.

Stack parameters and maximum NO_x, SO_2, H_2SO_4 mist, and PM_{10} emission rates under operating Case 4 conditions (100-percent load and 59°F ambient temperature with evaporative cooling) were used for the BPS SCCT Class I modeling. This operating case has the highest emission rates of the nine cases evaluated. Conservatively, the BPS SCCTs were premised to each operate continuously for 8,760 hr/yr, although their actual annual operating hours will be limited to no more than 2,500 hr/yr per CT. Table 10-1 summarizes the BPS SCCT emission source stack parameters and emission rates used in the CALPUFF modeling assessments.

10.7 MODEL RESULTS

BPS SCCT CALPUFF modeling results for Class I PSD increments, deposition impacts, and regional haze (i.e., visibility) at the Chassahowitzka NWA are discussed in the following subsections.

10.7.1 PSD CLASS I SIGNIFICANT IMPACT LEVEL ANALYSIS

Table 10-2 summarizes BPS SCCT NO_2, SO_2, and PM_{10} impacts with respect to the PSD Class I SILs. This table provides the highest annual average impacts (for NO_2, and PM_{10}), and highest 24-hour average impact (for PM_{10}).

All impacts are below the PSD Class I SILs for all modeled pollutants and all averaging periods. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2 and PM_{10} was not required.

10.7.2 SULFUR AND NITROGEN DEPOSITION

Table 10-3 summarizes the BPS SCCT total wet and dry annual sulfur and nitrogen deposition rates. As shown, sulfur and nitrogen deposition impacts will be below the FLM sulfur and nitrogen deposition analysis threshold (DAT) of 0.01 kilogram per hectare per year (kg/ha/yr).

Table 10-1. CALPUFF Modeling Data—BPS SCCTs

Parameter	Units	Value
SCCT (Per CT)		
Stack height	ft	60
Stack diameter	ft	9.5
Stack velocity	ft/sec	101.3
Stack temperature	°F	893
SO_2 emissions	lb/hr	1.9
H_2SO_4 emissions	lb/hr	0.21
NO_x emissions	lb/hr	32.0
PM_{10} emissions	lb/hr	2.5

Source: ECT, 2008.

Table 10-2. Summary of Bayside SCCT PSD Class I Air Quality Impacts—NO_2 and PM_{10}

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact Chassahowitzka NWA ($\mu g/m^3$)
NO_x	2001	Annual	0.0049
	2002		0.0061
	2003		0.0068
	Maximum		**0.0068**
PSD SIL			0.1
% of PSD SIL			6.8
Exceed PSD SIL			No
PM_{10}	2001	Annual	0.0010
	2002		0.0013
	2003		0.0013
	Maximum		**0.0013**
PSD SIL			0.2
% of PSD SIL			0.6
Exceed PSD SIL			No
PM_{10}	2001	24-Hour	0.013
	2002		0.015
	2003		0.019
	Maximum		**0.019**
PSD SIL			0.3
% of PSD SIL			6.3
Exceed PSD SIL			No

Source: ECT, 2008.

10.7.3 REGIONAL HAZE

The BPS SCCT regional haze assessment employed the EPA-approved version of the CALPUFF modeling suite and FLAG, NPS, and IWAQM recommended procedures including use of background extinction computation Method 2 (compute extinction from speciated PM measurements and hourly relative humidity adjustment applied to observed and modeled sulfate and nitrate), and the current IMPROVE light extinction algorithm.

The analytical procedures described for assessing regional haze compare project visibility impacts to natural background levels that would occur in the absence of all anthropogenic activities. In addition, the methods do not consider the effects of natural visibility impairment caused by rain or fog events. During such natural visibility impairment events, much lower visibility will occur compared to the assumed natural background level.

Table 10-4 summarizes BPS SCCT maximum 24-hour regional haze impacts. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and particulate matter fine [PMF]) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in Units of km and deciview (dv), and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be 4.2 percent, which is below the 5-percent FLM screening level value.

10.8 <u>SUMMARY</u>

Table 10-5 provides a summary of maximum BPS SCCT Chassahowitzka NWA air quality impacts, the PSD Class I area EPA significant impact levels, and FLM guidelines.

Table 10-3. Summary of Bayside SCCT PSD Class I Air Quality Impacts—Nitrogen and Sulfur Deposition

Pollutant	Year of Meteorology	Averaging Period	Chassahowitzka NWA	
			$\mu g/m^2/s$	kg/ha/yr
Total Wet and Dry Nitrogen Deposition	2001	Annual	0.0000101	0.00319
	2002		0.0000096	0.00302
	2003		0.0000114	0.00359
	Maximum		**0.0000114**	**0.00359**
FLM DAT				0.01
% of FLM DAT SIL				35.9
Exceed FLM DAT				No
Total Wet and Dry Sulfur Deposition	2001	Annual	0.0000025	0.00078
	2002		0.0000029	0.00090
	2003		0.0000026	0.00081
	Maximum		**0.00000286**	**0.00090**
FLM DAT				0.01
% of FLM DAT SIL				9.0
Exceed FLM DAT				No

Source: ECT, 2008.

Table 10-4. Bayside SCCT Chassahowitzka NWA Regional Haze Impacts

Maximum 24-Hour Average Impacts	Units	2001	2002	2003	Maximum
B_{ext-s} - SO_4	Mm^{-1}	0.032	0.034	0.061	0.061
B_{ext-s} - NO_3	Mm^{-1}	0.510	0.593	0.878	0.878
B_{ext-s} - Organic carbon (OC)	Mm^{-1}	0.032	0.026	0.035	0.035
B_{ext-s} - Elemental carbon (EC)	Mm^{-1}	0.027	0.022	0.029	0.029
B_{ext-s} - Total	Mm^{-1}	0.601	0.675	1.003	1.003
B_{ext-b} - Background	Mm^{-1}	23.2	24.4	24.2	24.4
Visual range, background	km	168.3	160.2	162.0	168.3
Visual range, background	mi	104.6	99.5	100.7	104.6
Visual range, background	dv	8.4	8.9	8.8	8.9
Relative humidity factor - f(RH)	—	5.27	6.58	6.28	6.58
Number of days with B_{ext} >5.0 %	—	0	0	0	0
Number of days with B_{ext} >10.0 %	—	0	0	0	0
Largest B_{ext} change	%	2.58	2.76	4.16	4.16
NPS significant impact, B_{ext} change	%	5.00	5.00	5.00	5.00
Exceed NPS significant impact	Yes/No	N	N	N	Y
Percent of NPS significant impact	%	51.6	55.2	83.2	83.2
Number of days with Delta deciview >(	—	0	0	0	0
Number of days with Delta deciview >1	—	0	0	0	0
Largest Delta deciview change	—	0.255	0.273	0.407	0.407
Receptor LCC Easting (km)	km	1,406.4	1,406.4	1,410.8	N/A
Receptor LCC Northing (km)	km	-1,152.5	-1,152.5	-1,153.7	N/A
Distance from Bayside CT5A (km)	km	2,875.8	2,875.8	2,880.3	N/A
Direction from Bayside CT5A (Vector°)	Vector°	114	114	114	N/A

Source: ECT, 2008.

Table 10-5. CALPUFF Model Chassahowitzka NWA Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.0068	0.1
PM_{10}	Annual	0.0013	0.2
	24-hour	0.019	0.3

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	0.00359	0.01
Sulfur	Annual	0.00090	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change B_{ext})	Significant Impact (% Change B_{ext})
Regional haze	24-Hour	4.2	5.0

Source: ECT, 2008.

11.0 REFERENCES

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APPENDIX A

APPLICATION FOR AIR PERMIT
TITLE V SOURCE

ECT
Environmental Consulting & Technology, Inc.

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

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

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

Air Operation Permit – Use this form to apply for:

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Tampa Electric Company**	
2. Site Name: **H.L. Culbreath Bayside Power Station**	
3. Facility Identification Number: **0570040**	
4. Facility Location Street Address or Other Locator: **3602 Port Sutton Road** City: **Tampa** County: **Hillsborough** Zip Code: **33619**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **David M. Lukcic, Manager Environmental Projects Environmental, Health, and Safety**
2. Application Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3. Application Contact Telephone Numbers... Telephone: **(813) 228 – 1095** ext. Fax: **(813) 228 – 1308**
4. Application Contact Email Address: **dmlukcic@tecoenergy.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 3\20\08	3. PSD Number (if applicable): 399
2. Project Number(s): - 1721	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being 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

PSD air construction permit application for four (4) Pratt & Whitney (P&W) FT8-3 SwiftPac aeroderivative simple-cycle combustion turbine (SCCT) units. Each P&W FT8-3 SwiftPac unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 MW. The BPS P&W FT8-3 SCCTs will be fired exclusively with pipeline-quality natural gas and will operate in peaking service for no more than 2,500 hours per year (hr/yr) per SCCT. The P&W Swift Pac SCCTs will be located at the existing Bayside Power Station (BPS) in Hillsborough County. A detailed description of the BPS SCCT Project is provided in Section 2.0.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
028	CT3A & CT3B; P&W Swift Pac Simple-Cycle Combustion Turbine Unit	AC1A	
029	CT4A & CT4B; P&W Swift Pac Simple-Cycle Combustion Turbine Unit	AC1A	
030	CT5A & CT5B; P&W Swift Pac Simple-Cycle Combustion Turbine Unit	AC1A	
031	CT6A & CT6B; P&W Swift Pac Simple-Cycle Combustion Turbine Unit	AC1A	
032	Emergency Generator Diesel Engine No. 1	AC1A	
033	Emergency Generator Diesel Engine No. 2	AC1A	

Application Processing Fee

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

Application processing fee of $7,500 is required pursuant to Rule 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: **David M. Lukcic, Manager of Environmental Programs** **Environmental, Health, and Safety**
2.	Owner/Authorized Representative Mailing Address Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3.	Owner/Authorized Representative Telephone Numbers Telephone: **(813) 228 – 1095** ext. Fax: **(813) 228 – 1308**
4.	Owner/Authorized Representative Email Address: **dmlukcic@tecoenergy.com**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* [signature] 3/19/08 Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification NOT APPLICABLE

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

1. Application Responsible Official Name:

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

   ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

   ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

   ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

   ☐ The designated representative at an Acid Rain source, CAIR source, or Hg Budget source.

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

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

5. Application Responsible Official E-mail Address:

6. Application Responsible Official Certification:

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

   Signature Date

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **Florida** Zip Code: **32606-5004**
3.	Professional Engineer Telephone Numbers... Telephone: **(352) 332 – 0444** ext. Fax: **(352) 332 - 6722**
4.	Professional Engineer Email Address: **tdavis@ectinc.com**
5.	Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis　　　　3/18/08

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 East (km) **360.00** North (km) **3,087.50**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Ben Willoughby, Environmental Coordinator**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **3602 Port Sutton Road** City: **Tampa** State: **Florida** Zip Code: **33619**
3. Facility Contact Telephone Numbers: Telephone: **(813) 627 -2880** ext. Fax: **(813) 627 -2951**
4. Facility Contact Email Address: **bpwilloughby@tecoenergy.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 E-mail Address:

FACILITY INFORMATION

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 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment: **NSPS for Stationary Gas Turbines, 40 CFR Part 60 Subpart GG, applies to all of the existing BPS combustion turbines.** **NSPS for Stationary Combustion Turbines, 40 CFR Part 60 Subpart KKKK, will apply to the P&W Swift Pac simple-cycle combustion turbines.** **NSPS for Stationary Compression Ignition Internal Combustion Engines, 40 CFR Part 60 Subpart IIII, will apply to the emergency generator diesel engines.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter – PM/PM_{10}	**A**	**N**
Sulfur Dioxide – SO_2	**A**	**N**
Nitrogen Oxide - NO_x	**A**	**N**
Carbon Monoxide – CO	**A**	**N**
Volatile Organic Compounds – VOC	**A**	**N**
Sulfuric Acid Mist - SAM	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps NOT APPLICABLE

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID'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: **Section 2.0** ☐ 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: **Section 2.0** ☐ 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: **Section 5.0** ☐ Previously Submitted, Date:______

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☒ Attached, Document ID: **Section 2.0** ☐ 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: **Section 4.0**
4. List of Exempt Emissions Units: ☐ Attached, Document ID: ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☒ Attached, Document ID: **Section 2.0** ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **Section 8.0** ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **Sections 7.0 and 10.0** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **Section 9.0** ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **Section 9.0** ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications **NOT APPLICABLE**

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

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

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 Onsite but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

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

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID: ☐ Previously Submitted, Date:__________
   ☐ Not Applicable (not an Acid Rain source) **Will be submitted separately.**

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID: __________ ☐ Previously Submitted, Date:__________
   ☐ Not Applicable (not a CAIR source)

   Will be submitted prior to commencing operation. See comment below.

3. Hg Budget Part (DEP Form No. 62-210.900(1)(c)):
   ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☒ Not Applicable (not a Hg Budget unit)

Additional Requirements Comment

Per Rule 62-213.420(1)(a)4.b., F.A.C. a CAIR unit not covered by a Title V permit prior to May 1, 2008, must submit a certified CAIR Part form to the Department prior to the unit commencing operation. The form shall be incorporated into the Title V permit upon issuance of an initial, revised, or renewal Title V permit, whichever comes first.

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:
Pratt & Whitney FT8-3 SwiftPac unit comprised of two simple cycle aeroderivative combustion turbines (SCCTs) and one common electrical generator.

3. Emissions Unit Identification Number: **028 (Unit 3; CT3A + CT 3B)**

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

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

☒ Acid Rain Unit

☒ CAIR Unit

☐ Hg Budget Unit

9. Package Unit:
Manufacturer: **Pratt & Whitney** Model Number: **FT8-3 Swift Pac**

10. Generator Nameplate Rating: **62** MW **(nominal)**

11. Emissions Unit Comment:

Unit 3 P&W FT8-3 SwiftPac is comprised of two identical simple cycle aeroderivative combustion turbines (CT-3A and CT-3B) and one common electrical generator. The two simple cycle CTs may operate independently.

Emissions Unit Control Equipment/Method: Control 1 of 2

1. Control Equipment/Method Description: **Water Injection – NOx Pollution Prevention**	
2. Control Device or Method Code: **028**	

Emissions Unit Control Equipment/Method: Control 2 of 2

1. Control Equipment/Method Description: **Oxidation Catalyst – CO Control**	
2. Control Device or Method Code: **109**	

Emissions Unit Control Equipment/Method: Control __ of __

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

Emissions Unit Control Equipment/Method: Control __ of __

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

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **336.3** million Btu/hr **(HHV)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day weeks/year	 days/week **2,500** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rate is at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Heat input will vary with CT load and ambient conditions.**	

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: **3A, 3B**	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: **9.5** feet
8. Exit Temperature: **893**°F	9. Actual Volumetric Flow Rate: **430,737** acfm	10. Water Vapor: **N/A** %
11. Maximum Dry Standard Flow Rate: **N/A** dscfm	12. Nonstack Emission Point Height: **N/A** feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :	
15. Emission Point Comment: **Exit temperature and actual volumetric flow rate data are at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Temperature and exhaust flow rate will vary with load and ambient conditions.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Pipeline quality natural gas burned in Unit 3 (Per CT).**		
2. Source Classification Code (SCC): **2-01-002-02**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.325**	5. Maximum Annual Rate: **812.5**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,034 (HHV)**
10. Segment Comment: **Maximum hourly and annual rates based on 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Maximum annual rate based on 2,500 hrs/yr/CT.**		

Segment Description and Rate: Segment __ of __

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx	**028**		**EL**
CO	**109**		**EL**
PM/PM10			**EL**
SO2			**EL**
VOC			**EL**

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control: **88**
3. Potential Emissions: **(Per CT)** **32.0** lb/hour **40.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** To tons/year	
6. Emission Factor: **N/A** Reference: **Vendor (P&W) data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential emission rates based on 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 2,500 hrs/yr/CT.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1** **(Per CT)**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **32.0** lb/hour **40.0** tons/year
5. Method of Compliance: **EPA Reference Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. (BACT) and NSPS Subpart KKKK.** **Allowable and equivalent allowable emissions are at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Equivalent allowable annual emission rate based on 2,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **90**
3. Potential Emissions: **(Per CT)** **9.1** lb/hour **5.9** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** To tons/year	
6. Emission Factor: **N/A** Reference: **Vendor (P&W) data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential hourly emission rate based on 50% load and 20°F ambient temperature.

Potential annual emission rates based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 2,500 hrs/yr/CT.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions **1** of **1** **(Per CT)**

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **21 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **9.1** lb/hour **5.9** tons/year
5. Method of Compliance: **EPA Reference Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable and equivalent allowable hourly emissions are at 50% load and 20°F ambient temperature per CT.** **Equivalent allowable annual emission rate based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 2,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **(Per CT)** **2.5** lb/hour **3.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** To tons/year	
6. Emission Factor: **N/A** Reference: **Vendor (P&W) data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential emission rates based on 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 2,500 hrs/yr/CT.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **10% opacity (surrogate for PM/PM_{10})**	4. Equivalent Allowable Emissions: **2.5** lb/hour **3.1** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(10)(b), F.A.C. (BACT).** **Allowable and equivalent allowable emissions are at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Equivalent allowable annual emission rate based on 2,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **(Per CT)** **1.9** lb/hour **2.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** To tons/year	
6. Emission Factor: **N/A** Reference: **Vendor (P&W) data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential emission rates based on 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 2,500 hrs/yr/CT.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **2.0 gr S / 100 scf natural gas**	4. Equivalent Allowable Emissions: **1.9** lb/hour **3.1** tons/year
5. Method of Compliance: **Fuel analysis per 40 CFR Part 75, Appendix D**	
6. Allowable Emissions Comment (Description of Operating Method): **Also subject to less stringent emission limits of NSPS Subpart KKKK.** **Allowable and equivalent allowable emissions are at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Equivalent allowable annual emission rate based on 2,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **50%**
3. Potential Emissions: **(Per CT)** **5.1** lb/hour **1.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** To tons/year	
6. Emission Factor: **N/A** Reference: **Vendor (P&W) data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential hourly emission rate based on 50% load and 20°F ambient temperature.

Potential annual emission rates based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 2,500 hrs/yr/CT.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **CO Limit (surrogate for VOC)**	4. Equivalent Allowable Emissions: **5.1** lb/hour **1.8** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable and equivalent allowable hourly emissions are at 50% load and 20°F ambient temperature per CT.** **Equivalent allowable annual emission rate based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 2,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions __ of __

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE 10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **10 %** Exceptional Conditions: **N/A %** Maximum Period of Excess Opacity Allowed: **N/A min/hour**	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(10)(b), F.A.C. (BACT).**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: **N/A %** Maximum Period of Excess Opacity Allowed: **N/A min/hour**	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b).**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor **1** of **3**

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

Continuous Monitoring System: Continuous Monitor **2** of **3**

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
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).**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **3**

1. Parameter Code: **CO_2**	2. Pollutant(s): **N/A**
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).**	

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: **Section 2.0** ☐ 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: **Section 5.0** ☐ 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** ☐ Not Applicable
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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1.	Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **Section 6.0** ☐ Not Applicable
3.	Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: **To be provided** ☐ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

NOT APPLICABLE

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

Additional Requirements Comment

NOTE:

Emission Unit 028 (Unit 3 - CT3A and CT3B), Emission Unit 029 (Unit 4 - CT4A and CT4B), Emission Unit 030 (Unit 5 - CT5A and CT5B), and Emission Unit 031 (Unit 6 - CT6A and CT6B) are identical emission units.

Section III. Emissions Unit Information provided for EU-028 (Unit 3, CT3A and CT3B) is also applicable to EU-029 (Unit 4, CT4A and CT4B), EU-030 (Unit 5, CT5A and CT5B), and EU-031 (Unit 6, CT6A and CT6B).

Emissions Unit Information Sections 2 through 4 are identical to Section 1, with the exception of identification numbers.

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:
   One, 800-kW Caterpillar internal combustion (IC) reciprocating engine/generator set; or equivalent.

3. Emissions Unit Identification Number: **032**

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

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

   ☐ Acid Rain Unit

   ☐ CAIR Unit

   ☐ Hg Budget Unit

9. Package Unit:
   Manufacturer: **Caterpillar** Model Number: **DSR4B Generator C27 TA Engine**

10. Generator Nameplate Rating: **0.800** MW

11. Emissions Unit Comment:
    Black start engine/generator set provides electricity to SCCT Units 3 - 6 in the event of power interruption from the grid.

    Diesel engine will be fired with ultra low sulfur diesel (ULSD) fuel oil.

<u>Emissions Unit Control Equipment/Method:</u> Control **1** of **1**

1. Control Equipment/Method Description: **Engine Combustion Design – NOx Pollution Prevention**
2. Control Device or Method Code: **024**

<u>Emissions Unit Control Equipment/Method:</u> Control of

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

<u>Emissions Unit Control Equipment/Method:</u> Control __ of __

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

<u>Emissions Unit Control Equipment/Method:</u> Control __ of __

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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **7.9** million Btu/hr **(HHV)**	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: hours/day days/week weeks/year **100** hours/year	
6. Operating Capacity/Schedule Comment: **Other than emergencies, the black start emergency generator will be operated approximately two hours per week for routine testing and maintenance.**	

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: **Black Start Generator**	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: **15** feet	7. Exit Diameter: **0.67** feet
8. Exit Temperature: **955°F**	9. Actual Volumetric Flow Rate: **6,046** acfm	10. Water Vapor: **N/A** %

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

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment **1** of **1**

1. Segment Description (Process/Fuel Type): **Ultra Low Sulfur Diesel (ULSD) fuel oil burned in IC reciprocating engine.**		
2. Source Classification Code (SCC): **2-02-001-02**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **0.0572**	5. Maximum Annual Rate: **5.72**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **137 (HHV)**
10. Segment Comment: **Maximum annual rate based on 100 hours per year operation for routine testing and maintenance, and excludes emergency operations.**		

Segment Description and Rate: Segment __ of __

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

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx			**EL**
CO			**EL**
VOC			**EL**
PM			**EL**

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **15.5** lb/hour **0.8** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **5.26 grams per horsepower hour (g/hp-hr)** Reference: **Vendor data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**
10. Calculation of Emissions: **Potential annual emission rate based on 100 hours per year operation for routine testing and maintenance, and excludes emergency operations.** **See Appendix B.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **6.4 g/kWh (4.8 g/hp-hr)**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit is for NO_x + NMHC per 40 CFR §89.112, Table 1.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.7** lb/hour **0.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.23 grams per horsepower hour (g/hp-hr)** Reference: **Vendor data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 100 hours per year operation for routine testing and maintenance, and excludes emergency operations.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **3.5 g/kWh (2.6 g/hp-hr)**	4. Equivalent Allowable Emissions: **7.7** lb/hour **N/A** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit per 40 CFR §89.112, Table 1.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.1** lb/hour **0.004** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.03 grams per horsepower hour (g/hp-hr)** Reference: **Vendor data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 100 hours per year operation for routine testing and maintenance, and excludes emergency operations.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **6.4 g/kWh (4.8 g/hp-hr)**	4. Equivalent Allowable Emissions: **N/A** lb/hour **N/A** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit is for NO_x + NMHC per 40 CFR §89.112, Table 1.**	

Allowable Emissions Allowable Emissions __ of __

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

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

(Optional for unregulated emissions units.)

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

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.07** lb/hour **0.004** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: **0.024 grams per horsepower hour (g/HP-hr)** Reference: **Vendor data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): tons/year **N/A**	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): tons/year **N/A**	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years **N/A**

10. Calculation of Emissions:

Potential annual emission rate based on 100 hours per year operation for routine testing and maintenance, and excludes emergency operations.

See Appendix B.

11. Potential, Fugitive, and Actual Emissions Comment:

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.20 g/kWh (0.15 g/hp-hr)**	4. Equivalent Allowable Emissions: **0.4** lb/hour **N/A** tons/year
5. Method of Compliance: **Engine manufacturer certification**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable limit per 40 CFR §89.112, Table 1.**	

Allowable Emissions Allowable Emissions __ of __

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation **1** of **2**

1. Visible Emissions Subtype: **VE 20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-296.320(4)(b)**	

Visible Emissions Limitation: Visible Emissions Limitation **2** of **2**

1. Visible Emissions Subtype: **Multiple Limits**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **N/A** % Exceptional Conditions: **N/A** % Maximum Period of Excess Opacity Allowed: **N/A** min/hour	
4. Method of Compliance: **40 CFR Part 86, Subpart I**	
5. Visible Emissions Comment: **40 CFR §89.113 opacity limits.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor __ of __ NOT APPLICABLE

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

Continuous Monitoring System: Continuous Monitor ___ of ___

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **Section 2.0** ☐ 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: **Section 5.0** ☐ 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** ☐ Not Applicable
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

I. EMISSIONS UNIT ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)): ☒ Attached, Document ID: **Section 5.0** ☐ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☒ Attached, Document ID: **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

NOT APPLICABLE

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

Additional Requirements Comment

NOTE:

Emission Unit 032 (Emergency Generator No. 1) and Emission Unit 033 (Emergency Generator No. 2) are identical emission units.

Section III. Emissions Unit Information provided for EU-032 (Emergency Generator No. 1) is also applicable to EU-033 (Emergency Generator No. 2).

Emissions Unit Information Section 6 is identical to Section 5, with the exception of identification numbers.

APPENDIX B

EMISSION RATE CALCULATIONS

ECT
Environmental Consulting & Technology, Inc.

Appendix B - TEC Bayside Power Station
Simple Cycle Combustion Turbines; Units 3 - 6
Emission Rate Calculations - List of Tables

Table No.	Description
	Operation Sources
B-1	Annual Emission Rate Summary
B-2	CT Operating Cases
B-3	CT PM/PM_{10}, SO_2, H_2SO_4 Mist, and Lead Hourly Emission Rates - Natural Gas (Per CT)
B-4	CT NO_x, CO, VOC, and NH_3 Hourly Emission Rates - Natural Gas (Per CT)
B-5	CT HAP Hourly Emission Rates - Natural Gas (Per CT)
B-6	CT HAP Annual Emission Rates
B-7	CT Criteria Pollutant, H_2SO_4 Mist, and NH_3 Annual Emission Rates - Annual Profile 1
B-8	CT Exhaust Flow Rates - Natural Gas (Per CT)
B-9	CT Fuel Flow Rates - Natural Gas (Per CT)
B-10	Emergency Diesel Engine Emission Rates - Criteria Pollutant Pollutants
B-11	Emergency Diesel Engine Emission Rates - HAPs
	Stack Parameters
B-12	CT - Natural Gas (Per CT)
B-13	Emergency Diesel Engines

Source: ECT, 2008.

Table B-1. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
Annual Emission Rate Summary

Pollutant	Potential Annual Emissions (tpy)		
	P&W CTs (8 CTs)	Emergency Diesel Engines	Project Totals
Criteria Pollutants			
NO_x	320.0	1.6	**321.6**
CO	46.7	0.068	**46.8**
VOC	13.5	0.0089	**13.5**
SO_2	18.6	0.0012	**18.6**
PM_{10} (filterable + condensable)	25.0	0.007	**25.0**
Pb	0.0016	Neg.	**0.0016**
Hazardous Air Pollutants			
Formaldhyde[1]	1.2	Neg.	**1.2**
Total HAPs	1.7	Neg.	**1.7**
Other Pollutants			
H_2SO_4 Mist	2.1	Neg.	**2.1**
PM (filterable)[2]	6.3	0.0071	**6.3**
Other Constituents			
CO_2	369,953	130	**370,083**

Neg. - negligible

[1] Maximum individual HAP.
[2] For P&W CTs, all PM is $PM_{2.5}$ or less. PM (filterable) is assumed to be 25 percent of total PM_{10}.

Sources: P&W, 2008.
TEC, 2008.
ECT, 2008.

Table B-2. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
CT Operating Scenarios - Pratt & Whitney FT8-3
SwiftPac™ Units

Case	Ambient Temperature (°F)	CT Compressor Inlet Temperature (°F)	Load (%)	Evaporative Cooling	Natural Gas Firing	Annual Profile (hr/yr)
1-G	20	20	100		X	
2-G	20	20	75		X	
3-G	20	20	50		X	
4-G	59	52	100	X	X	2,500
5-G	59	52	75	X	X	
6-G	59	52	50	X	X	
7-G	90	79	100	X	X	
8-G	90	79	75	X	X	
9-G	90	79	50	X	X	

Note: Each FT8-3 SwiftPac™ unit consists of two combustion turbines and one common generator.

Sources: P&W, 2008.
TEC, 2008.
ECT, 2008.

Table B-3. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Lead Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case	Load (%)	PM/PM10[1] lb/hr	PM/PM10[1] g/sec	SO2[2] lb/hr	SO2[2] g/sec	H2SO4[3] lb/hr	H2SO4[3] g/sec	Lead[4] lb/hr	Lead[4] g/sec
20	1-Gas	100	2.5	0.32	1.84	0.23	0.21	0.027	0.00016	0.000021
	2-Gas	75	2.5	0.32	1.42	0.18	0.16	0.021	0.00013	0.000016
	3-Gas	50	2.5	0.32	1.04	0.13	0.12	0.015	0.00009	0.000012
59	4-Gas	100	2.5	0.32	1.86	0.23	0.21	0.027	0.00016	0.000021
	5-Gas	75	2.5	0.32	1.44	0.18	0.17	0.021	0.00013	0.000016
	6-Gas	50	2.5	0.32	1.06	0.13	0.12	0.015	0.00009	0.000012
90	7-Gas	100	2.5	0.32	1.75	0.22	0.20	0.025	0.00016	0.000020
	8-Gas	75	2.5	0.32	1.38	0.17	0.16	0.020	0.00012	0.000015
	9-Gas	50	2.5	0.32	1.02	0.13	0.12	0.015	0.00009	0.000011
		Maximums	**2.5**	**0.32**	**1.86**	**0.23**	**0.21**	**0.027**	**0.00016**	**0.000021**

[1] Total particulate matter as measured by EPA RM 201 or 201A, and 202.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5-percent conversion of SO_2 to H_2SO_4.
[4] Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.

Sources: P&W, 2008.
ECT, 2008.

Table B-4. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
Hourly NO_x, CO, AND VOC Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case Case	Load (%)	NO_x ppmvd[3]	NO_x lb/hr	NO_x g/sec	CO ppmvd[3]	CO lb/hr	CO g/sec	VOC[1,2] ppmvd[3]	VOC[1,2] lb/hr	VOC[1,2] g/sec
20	1-Gas	100	25	31.6	3.98	8.0	6.2	0.77	3.0	1.3	0.16
	2-Gas	75	25	24.4	3.07	14.1	8.4	1.05	7.8	2.7	0.33
	3-Gas	50	25	18.2	2.29	20.9	9.1	1.15	20.2	5.1	0.64
59	4-Gas	100	25	32.0	4.03	6.0	4.7	0.59	3.0	1.4	0.17
	5-Gas	75	25	24.8	3.12	11.6	7.0	0.89	5.5	1.9	0.24
	6-Gas	50	25	18.2	2.29	14.8	6.6	0.83	8.6	2.2	0.27
90	7-Gas	100	25	30.2	3.81	6.0	4.4	0.56	3.0	1.3	0.16
	8-Gas	75	25	23.7	2.99	9.3	5.4	0.68	3.8	1.3	0.16
	9-Gas	50	25	17.5	2.21	14.3	6.1	0.77	8.0	2.0	0.25
		Maximums	**25**	**32.0**	**4.03**	**20.9**	**9.1**	**1.15**	**20.2**	**5.1**	**0.64**

[1] 50-percent control for oxidation catalyst.

[2] Expressed as methane.

[3] Corrected to 15-percent oxygen.

Sources: P&W, 2008.
ECT, 2008.

Table B-5. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
HAP Hourly Emission Rates - Natural Gas (Per CT)

Parameter	Units	Value								
Case	N/A	1-G	2-G	3-G	4-G	5-G	6-G	7-G	8-G	9-G
Maximum CT Hourly Fuel Flow:	10^6 Btu/hr (HHV)	332.2	257.0	189.0	336.3	260.7	191.5	317.3	249.7	184.1

Hazardous Air Pollutant	Gas Emission Factor[1-4] (lb/10^6 Btu)	Hourly Emissions (lb/hr)								
		1-G	2-G	3-G	4-G	5-G	6-G	7-G	8-G	9-G
1,3-Butadiene	2.15E-07	7.14E-05	5.53E-05	4.06E-05	7.23E-05	5.61E-05	4.12E-05	6.82E-05	5.37E-05	3.96E-05
Acetaldehyde	2.00E-05	6.64E-03	5.14E-03	3.78E-03	6.73E-03	5.21E-03	3.83E-03	6.35E-03	4.99E-03	3.68E-03
Acrolein	3.20E-06	1.06E-03	8.22E-04	6.05E-04	1.08E-03	8.34E-04	6.13E-04	1.02E-03	7.99E-04	5.89E-04
Arsenic (As)	1.96E-07	6.51E-05	5.04E-05	3.70E-05	6.59E-05	5.11E-05	3.76E-05	6.22E-05	4.90E-05	3.61E-05
Benzene	6.00E-06	1.99E-03	1.54E-03	1.13E-03	2.02E-03	1.56E-03	1.15E-03	1.90E-03	1.50E-03	1.10E-03
Beryllium (Be)	1.18E-08	3.91E-06	3.02E-06	2.22E-06	3.96E-06	3.07E-06	2.25E-06	3.73E-06	2.94E-06	2.17E-06
Cadmium (Cd)	1.08E-06	3.58E-04	2.77E-04	2.04E-04	3.63E-04	2.81E-04	2.07E-04	3.42E-04	2.69E-04	1.99E-04
Chromium (Cr)	1.37E-06	4.56E-04	3.53E-04	2.59E-04	4.62E-04	3.58E-04	2.63E-04	4.36E-04	3.43E-04	2.53E-04
Ethylbenzene	1.60E-05	5.32E-03	4.11E-03	3.02E-03	5.38E-03	4.17E-03	3.06E-03	5.08E-03	4.00E-03	2.95E-03
Formaldehyde	3.55E-04	1.18E-01	9.12E-02	6.71E-02	1.19E-01	9.26E-02	6.80E-02	1.13E-01	8.87E-02	6.54E-02
Lead (Pb)	4.90E-07	1.63E-04	1.26E-04	9.26E-05	1.65E-04	1.28E-04	9.39E-05	1.56E-04	1.22E-04	9.03E-05
Manganese (Mn)	3.73E-07	1.24E-04	9.57E-05	7.04E-05	1.25E-04	9.71E-05	7.14E-05	1.18E-04	9.30E-05	6.86E-05
Mercury (Hg)	2.55E-07	8.47E-05	6.55E-05	4.82E-05	8.57E-05	6.65E-05	4.88E-05	8.09E-05	6.37E-05	4.69E-05
Naphthalene	6.50E-07	2.16E-04	1.67E-04	1.23E-04	2.19E-04	1.69E-04	1.24E-04	2.06E-04	1.62E-04	1.20E-04
Nickel (Ni)	2.06E-06	6.84E-04	5.29E-04	3.89E-04	6.92E-04	5.37E-04	3.94E-04	6.53E-04	5.14E-04	3.79E-04
Polycyclic Aromatic Hydrocarbons	1.10E-06	3.65E-04	2.83E-04	2.08E-04	3.70E-04	2.87E-04	2.11E-04	3.49E-04	2.75E-04	2.03E-04
Propylene Oxide	1.45E-05	4.82E-03	3.73E-03	2.74E-03	4.88E-03	3.78E-03	2.78E-03	4.60E-03	3.62E-03	2.67E-03
Selenium (Se)	2.35E-08	7.82E-06	6.05E-06	4.45E-06	7.91E-06	6.13E-06	4.51E-06	7.47E-06	5.88E-06	4.33E-06
Toluene	6.50E-05	2.16E-02	1.67E-02	1.23E-02	2.19E-02	1.69E-02	1.24E-02	2.06E-02	1.62E-02	1.20E-02
Xylene	3.20E-05	1.06E-02	8.22E-03	6.05E-03	1.08E-02	8.34E-03	6.13E-03	1.02E-02	7.99E-03	5.89E-03
Maximum Individual HAP		**0.118**	**0.091**	**0.067**	**0.119**	**0.093**	**0.068**	**0.113**	**0.089**	**0.065**
Total HAPs		**0.173**	**0.134**	**0.098**	**0.175**	**0.135**	**0.100**	**0.165**	**0.130**	**0.096**

[1] - All emission factors except metals, EPA AP-42, Section 3.1 Stationary Gas Turbines, Table 3.1-3., April 2000.
[2] - Organic pollutant emission factors reduced by 50 percent due to use of oxidation catalyst.
[3] - Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.
[4] - Metallic emission factors, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-4., July 1998.

Sources: P&W, 2008.
ECT, 2008.

Table B-6. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
HAP Annual Emission Rates (8 CTs)

HAP	Annual Emissions Profile (tpy)
1,3-Butadiene	7.23E-04
Acetaldehyde	6.73E-02
Acrolein	1.08E-02
Arsenic	6.59E-04
Benzene	2.02E-02
Beryllium	3.96E-05
Cadmium	3.63E-03
Chromium	4.62E-03
Ethylbenzene	5.38E-02
Formaldehyde	1.19E+00
Lead	1.65E-03
Manganese	1.25E-03
Mercury	8.57E-04
Naphthalene	2.19E-03
Nickel	6.92E-03
Polycyclic Aromatic Hydrocarbons	3.70E-03
Propylene Oxide	4.88E-02
Selenium	7.91E-05
Toluene	2.19E-01
Xylene	1.08E-01
Maximum Individual HAP	1.194
Total HAPs	1.747

Sources: P&W, 2008.
ECT, 2008.

Table B-7. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
Annual Criteria and H_2SO_4 Mist Pollutant Emission Rates

Source	Case	Number of CTs	Annual Operations (hr/yr)	Emission Rates					
				NO_x		CO		VOC	
				lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Units 3-6	4-Gas	8	2,500	256.0	320.0	37.4	46.7	10.8	13.5
		Totals	**2,500**	**N/A**	**320.0**	**N/A**	**46.7**	**N/A**	**13.5**

Source	Case	Number of CTs	Annual Operations (hr/yr)	Emission Rates							
				PM/PM_{10}		SO_2		H_2SO_4		Lead	
				lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Units 3-6	4-Gas	8	2,500	20.0	25.0	14.9	18.6	1.7	2.1	0.0013	0.00165
		Totals	**2,500**	**N/A**	**25.0**	**N/A**	**18.6**	**N/A**	**2.1**	**N/A**	**0.0016**

Sources: P&W, 2008.
ECT, 2008.

Table B-8. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
CT Exhaust Data, Natural Gas (Per CT)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100% Load			75% Load			50% Load		
		20°F	59°F	90°F	20°F	59°F	90°F	20°F	59°F	90°F
	Case	1-Gas	4-Gas	7-Gas	2-Gas	5-Gas	8-Gas	3-Gas	6-Gas	9-Gas
Ar	39.944	0.871	0.858	0.842	0.881	0.868	0.851	0.889	0.877	0.859
N_2	28.013	73.2	72.1	70.8	74.1	73.0	71.5	74.7	73.7	72.2
O_2	31.999	13.5	12.9	12.6	14.6	14.0	13.5	15.4	14.9	14.4
CO_2	44.010	3.14	3.29	3.27	2.72	2.88	2.93	2.38	2.52	2.57
H_2O	18.015	9.25	10.77	12.45	7.76	9.29	11.24	6.57	8.05	10.00
	Totals	100.0	99.9	100.0	100.1	100.0	100.0	99.9	100.0	100.0
Exhaust MW (lb/mole)		28.22	28.06	27.88	28.38	28.22	28.00	28.44	28.32	28.11
Exhaust Flow (lb/sec)		212.0	204.0	192.0	190.0	182.0	169.0	161.0	153.0	143.0
Exhaust Temp. (°F)		828	893	917	748	817	864	701	767	814
(K)		715	751	765	671	709	735	645	681	708
Exhaust O_2 (Vol %, Dry)		14.88	14.46	14.39	15.83	15.43	15.21	16.48	16.20	16.00

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100% Load			75% Load			50% Load		
	20°F	59°F	90°F	20°F	59°F	90°F	20°F	59°F	90°F
Case	1-Gas	4-Gas	7-Gas	2-Gas	5-Gas	8-Gas	3-Gas	6-Gas	9-Gas
ACFM	423,625	430,737	415,146	354,140	360,629	349,844	287,770	290,208	283,774
Stack Dia. (ft)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Velocity (fps)	99.6	101.3	97.6	83.3	84.8	82.3	67.7	68.2	66.7
Velocity (m/s)	30.4	30.9	29.8	25.4	25.8	25.1	20.6	20.8	20.3
SCFM, Dry[1]	157,597	149,989	139,366	142,778	135,257	123,833	122,274	114,829	105,847
SCFM[1] (15% O_2, Dry)	160,908	163,793	153,733	122,734	125,312	119,435	91,541	91,387	87,907

[1] At 68 °F.

Sources: P&W, 2008.
ECT, 2008.

Table B-9. TEC Bayside Generating Station
Simple-Cycle Combustion Turbines; Units 3 - 6
CT Fuel Flow Rate Data (Per CT) - Natural Gas*

	100% Load			75% Load			50% Load		
	20°F	59°F	90°F	20°F	59°F	90°F	20°F	59°F	90°F
Case	1-Gas	4-Gas	7-Gas	2-Gas	5-Gas	8-Gas	3-Gas	6-Gas	9-Gas
Heat Input - LHV (MMBtu/hr)	299.5	303.1	286.0	231.7	235.0	225.1	170.3	172.6	166.0
Heat Input - HHV (MMBtu/hr)	332.2	336.3	317.3	257.0	260.7	249.7	189.0	191.5	184.1
Fuel Rate (lb/hr)	14,487	14,665	13,836	11,207	11,368	10,890	8,239	8,352	8,029
Fuel Rate (10^6 ft^3/hr)	0.321	0.325	0.307	0.249	0.252	0.242	0.183	0.185	0.178
Fuel Rate (lb/sec)	4.024	4.074	3.843	3.113	3.158	3.025	2.289	2.320	2.230

*Includes 5.0-percent margin.

Sources: P&W, 2008.
ECT, 2008.

Table B-10. TEC Bayside Power Station
Emergency Diesel Engines
Criteria Pollutant Emission Rates

Parameter	Units	Emergency Generator Engines (Per Engine)
Vendor	-	Caterpillar
Model	-	C27 TA
Output	hp	1,340
	kWe	800
Hours	hr/yr	100
Max. ULSD Fuel Flow	gal/hr	57.2
ULSD Fuel S Content	wt % S	0.0015
ULSD Fuel Density	lb/gal	7.08
Criteria Pollutant		
NO_x	g/hp-hr	5.26
	lb/hr	15.5
	ton/yr	0.78
CO	g/hp-hr	0.23
	lb/hr	0.68
	ton/yr	0.034
VOC	g/hp-hr	0.03
	lb/hr	0.1
	ton/yr	0.004
$PM/PM_{10}/PM_{2.5}$	g/hp-hr	0.024
	lb/hr	0.071
	ton/yr	0.004
SO_2	g/hp-hr	0.004
	lb/hr	0.012
	ton/yr	0.0006

Sources: Caterpillar, 2007.
ECT, 2008

Table B-11. TEC Bayside Power Station
Emergency Diesel Engines
HAP Emission Rates

Parameter	Units	Emergency Generator Engines (per Engine)
Vendor	—	Caterpillar
Model	—	C27 TA
Output	hp	1340
		800
Hours	hr/yr	100
Max. ULSD Fuel Flow	gal/hr	57.2
ULSD Fuel Heat Content	Btu/gal (HHV)	138,000
ULSD Fuel Density	lb/gal	7.08
Engine Heat Input	MMBtu/hr (HHV)	7.89
Hazardous Air Pollutant		
1,3-Butadiene	lb/MMBtu	3.91E-05
	lb/hr	3.09E-04
	ton/yr	1.54E-05
Acetaldehyde	lb/MMBtu	7.67E-04
	lb/hr	6.05E-03
	ton/yr	3.03E-04
Acrolein	lb/MMBtu	9.25E-05
	lb/hr	7.30E-04
	ton/yr	3.65E-05
Benzene	lb/MMBtu	9.33E-04
	lb/hr	7.36E-03
	ton/yr	3.68E-04
Formaldehyde	lb/MMBtu	1.18E-03
	lb/hr	9.31E-03
	ton/yr	4.66E-04
Polycyclic Aromatic Hydrocarbons (PAH)	lb/MMBtu	1.68E-04
	lb/hr	1.33E-03
	ton/yr	6.63E-05
Toluene	lb/MMBtu	4.09E-04
	lb/hr	3.23E-03
	ton/yr	1.61E-04
Xylene	lb/MMBtu	2.85E-04
	lb/hr	2.25E-03
	ton/yr	1.12E-04

Sources: Caterpillar, 2007.
ECT, 2008

Table B-12. TEC Bayside Power Station
Simple-Cycle Combustion Turbines; Units 3 - 6
CT Stack Parameters - Natural Gas

Height Above Grade	60	ft
	18.29	m
Exit Diameter	9.5	ft
	2.90	m

Parameter	Operating Case	1-G	2-G	3-G	4-G	5-G	6-G	7-G	8-G	9-G
	Load (%)	100	75	50	100	75	50	100	75	50
	Ambient Temp. (°F)	20	20	20	59	59	59	90	90	90
	CT Inlet Temp. (°F)	20	20	20	52	52	52	79	79	79
Flow Rate	acfm	423,625	354,140	287,770	430,737	360,629	290,208	415,146	349,844	283,774
Exit Velocity	ft/sec	99.61	83.27	67.66	101.28	84.80	68.24	97.61	82.26	66.72
	m/sec	30.36	25.38	20.62	30.87	25.85	20.80	29.75	25.07	20.34
Exit Temperature	°F	828.00	748.00	701.00	893.00	817.00	767.00	917.00	864.00	814.00
	K	715.37	670.93	644.82	751.48	709.26	681.48	764.82	735.37	707.59

Sources: P&W, 2008.
ECT, 2008.

Table B-13. TEC Bayside Power Station Emergency Diesel Engines Stack Parameters

Parameter	Units	Generator Diesel Engine (per Engine)
Height Above Grade	ft meters	15.0 4.57
Exit Diameter	ft meters	0.67 0.20
Stack Area	ft^2	0.35
Flow Rate	acfm	6,046
Exit Velocity	ft/sec m/sec	288.7 88.0
Exit Temperature	°F K	955.0 785.9

Sources: Caterpillar, 2007.
ECT, 2008

APPENDIX C

DISPERSION MODELING FILES

Environmental Consulting & Technology, Inc.

Bayside SCCT Project
Class I Area Dispersion Modeling Files

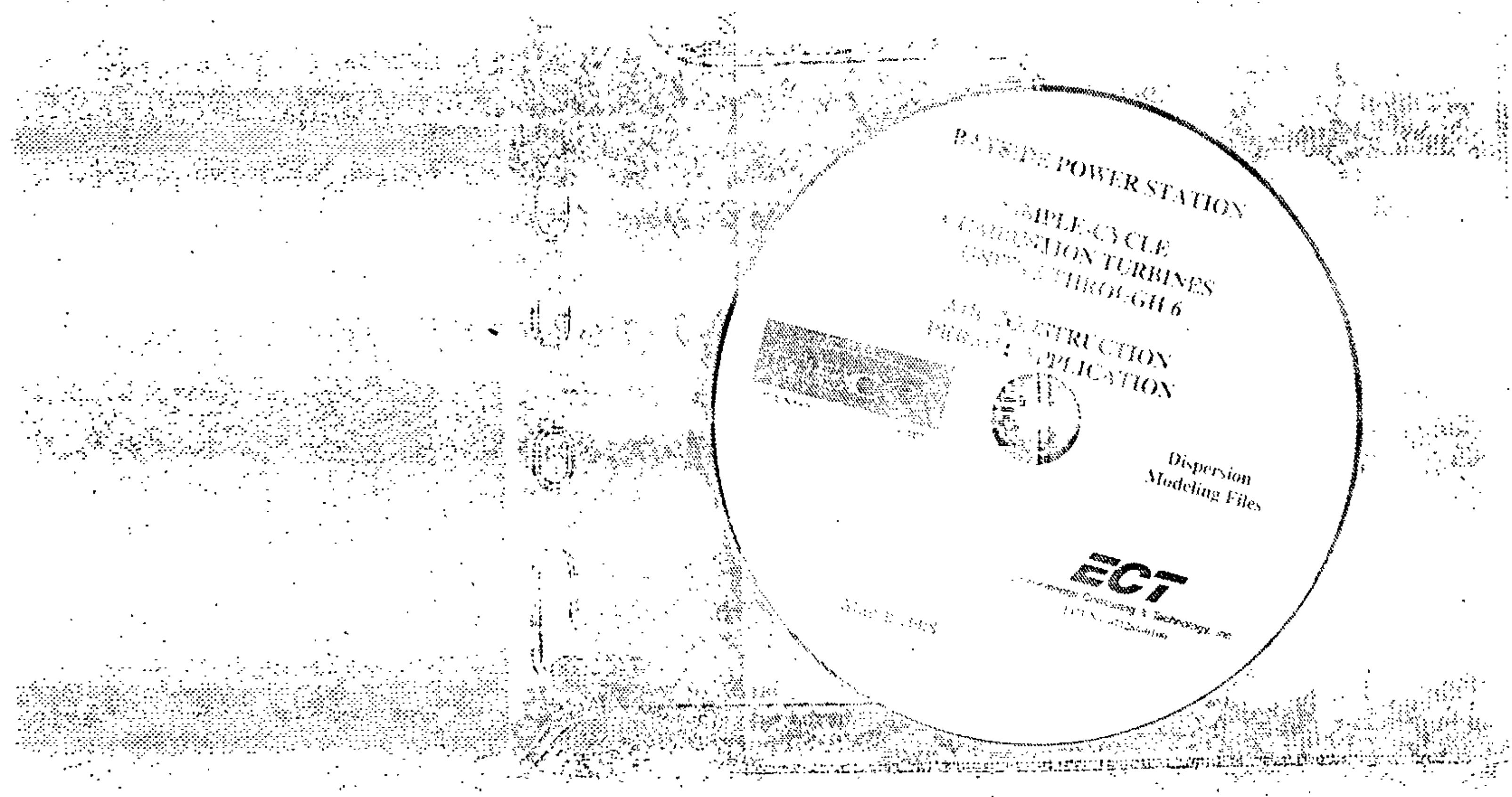
Directory Name	No. of Files	File Name	File Description
CLASS I/PUFF-INP	3	ngCTYY.inp	CALPUFF input files
	3	o3epa_YY.dat	Ambient ozone files
		YY = 01, 02, and 03	
Subtotal Files	6		
CLASS I/PUFF-OUT	3	NGCTYY.CON	CALPUFF output concentration files
	3	NGCTYYDF.CON	CALPUFF output concentration files, dry deposition flux files
	3	NGCTYYWF.CON	CALPUFF output concentration files, wet deposition flux files
	3	NGCTYY.LST	CALPUFF output concentration list files
	3	VISYY.ZIP	CALPUFF output visibility relative humidity (RH) files
		YY = 01, 02, and 03	
Subtotal Files	15		
CLASS I/UTIL-INP	3	YYutilVS.inp	POSTUTIL input files, PM_{10} and Visibility Species Processing
	3	YYutilDP.inp	POSTUTIL input files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	6		
CLASS I/UTIL-OUT	3	YYutilVS.con	POSTUTIL output concentration files, PM_{10} and Visibility Species Processing
	3	YYutilDP.con	POSTUTIL output concentration files, Nitrogen and Sulfur Deposition
	3	YYutilVS.lst	POSTUTIL output list files, PM_{10} and Visibility Species Processing
	3	YYutilDP.lst	POSTUTIL output list files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	12		
CLASS I/POST-INP	3	noxCHASYY.inp	CALPOST input NO_2 files - Chassahowitzka NWA
	3	pmCHASYY.inp	CALPOST input PM_{10} files - - Chassahowitzka NWA
	3	ndepCHASYY.inp	CALPOST input nitrogen deposition files - Chassahowitzka NWA
	3	sdepCHASYY.inp	CALPOST input sulfur deposition files - Chassahowitzka NWA
	3	visCHASYY.inp	CALPOST input visibility files; Method 2 - Chassahowitzka NWA
		YY = 01, 02, and 03	
Subtotal Files	15		
CLASS I/POST-OUT	3	noxCHASYY.out	CALPOST output NO_2 files - Chassahowitzka NWA
	3	pmCHASYY.out	CALPOST output PM_{10} files - - Chassahowitzka NWA
	3	ndepCHASYY.out	CALPOST output nitrogen deposition files - Chassahowitzka NWA
	3	sdepCHASYY.out	CALPOST output sulfur deposition files - Chassahowitzka NWA
	3	visCHASYY.out	CALPOST output visibility files; Method 2 - Chassahowitzka NWA
		YY = 01, 02, and 03	
Subtotal Files	15		
Total Files	69		

Source: ECT, 2008.

Bayside SCCT Project
Class II Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
CLASS II/AERMET DATA	5	TPATPAYY.PFL	Meteorological Data - Tampa Intl. Airport Surface and Upper Air profile files
	5	TPATPAYY.SFC	Meteorological Data - Tampa Intl. Airport Surface and Upper Air surface files
		YY = 01 - 05	
Subtotal Files	10		
CLASS II/GEP	1	baygep.bpi	Building Profile Input Program (BPIP) input file
	1	baygep.pro	Building Profile Input Program (BPIP) output file
	1	baygep.sup	Building Profile Input Program (BPIP) output file
Subtotal Files	3		
CLASS II/AERMOD INPUT	5	BAYYY.inp	AERMOD input files; nominal 1.0 g/s emission rate
	1	BAY.ROU	AERMOD receptor grid file
		YY = 01 - 05	
Subtotal files	6		
CLASS II/AERMOD OUTPUT	5	BAYYY.OUT	AERMOD output files; nominal 1.0 g/s emission rate
		YY = 01 - 05	
Subtotal files	5		
Total Files	24		

Source: ECT, 2008.


POWER STATION
TURBINES
Dispersion
Modeling Files
ECT