BIG BEND STATION

SIMPLE-CYCLE COMBUSTION TURBINES UNIT 4

AIR CONSTRUCTION PERMIT APPLICATION

Prepared for:

TECO
TAMPA ELECTRIC
Tampa, Florida

Prepared by:

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ECT No. 071286-0100

August 2008

Original Permit Application Rcvd 8-22-08

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BUREAU OF AIR REGULATION

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August 21, 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. 7900 7283 8881

Re: Tampa Electric Company
Big Bend Power Station
Air Construction Permit Application for
Two Simple-Cycle Combustion Turbines (SCCTs)

Dear Ms. Vielhauer,

Tampa Electric Company (TEC) requests an air construction permit to install and operate two simple-cycle combustion turbines (SCCTs) at its existing Big Bend Power Station (BBS). The BBS SCCT project consists of one Pratt & Whitney (P&W) FT8-3 SwiftPac aeroderivative CT unit. The 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 BBS P&W FT8-3 SCCTs will be fired with pipeline-quality natural gas or ultra low sulfur diesel and will operate in peaking service for no more than 3,500 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 Big Bend's SCCTs..

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

Sincerely,

Paul L. Carpinone

Paul L. Carpinone, P.E.
Director
Environmental, Health & Safety

EHS/rlk/JMW162

Enclosure

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

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Tampa Electric Company (TEC) plans to construct and operate two simple-cycle combustion turbines (SCCTs) at its existing Big Bend Station (BBS). The BBS is located on Wyandotte Road in Apollo Beach, Hillsborough County, Florida.

BBS combustion sources presently include four solid fuel steam boilers (Units 1 – 4) and three SCCTs (combustion turbines [CTs] 1 – 3). Ancillary emission units include solid fuel, limestone, and flyash storage and handling equipment.

The BBS SCCT project consists of one nominal 62-megawatt (MW), simple-cycle aeroderivative Pratt & Whitney Power Systems (PWPS) FT8-3® SWIFTPAC® unit. The PWPS FT8-3® SWIFTPAC® unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 MW. Accordingly, there will be a total of two SCCTs and one generator. The BBS PWPS FT8-3® SCCTs will be fired primarily with pipeline-quality natural gas. Ultra low sulfur diesel (ULSD) fuel oil will serve as a back-up fuel source. The new SCCTs will operate in peaking service for no more than 3,500 hours per year (hr/yr) per SCCT, including no more than 500 hr/yr per SCCT of oil firing. Accordingly, maximum natural gas firing annual hours at rated load will range from 3,500 hr/yr (with no oil firing) to 3,000 hr/yr (with 500 hr/yr of oil firing). The SCCTs will utilize water injection and oxidation catalyst technologies to control emissions of nitrogen oxides (NO_x) and carbon monoxide (CO), respectively.

The SCCT peaker project will also include one black start emergency diesel engine/generator set. Excluding emergency conditions, the diesel engine/generator set will only be operated for approximately 2 hours per week (100 hr/yr) for routine testing and maintenance purposes. The emergency diesel engine will be fired with ULSD fuel oil.

Based on an evaluation of anticipated worst-case annual operating scenarios, the BBS SCCT project will have the potential to emit 122.4 tons per year (tpy) of NO_x, 16.5 tpy of CO, 11.3 tpy of particulate matter (PM)/particulate matter less than or equal to

10 micrometers aerodynamic diameter (PM_{10}), 6.6 tpy of sulfur dioxide (SO_2), and 4.7 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, the BBS SCCT project will potentially emit 0.8 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of organic compounds associated with natural gas combustion.

The planned construction start date for the BBS SCCT project is September 30, 2008. The projected date for the facility to begin commercial operation is May 15, 2009, following initial equipment start-up and completion of required performance testing.

The existing BBS 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 tpy. Accordingly, BBS is an existing major source with respect to the PSD permitting program. Prior to the commencement of operation of the BBS SCCT project, existing BBS SCCTs CT-1, CT-3, and CT-3 will permanently cease operations. An analysis of the net change in emissions pursuant to Rule 62-212.400(2), Florida Administrative Code (F.A.C.) indicates that the BBS SCCT project is not subject to PSD review for any pollutant.

The BBS SCCT project is potentially 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]). However, the effectiveness of Subpart YYYY was stayed by the U.S. Environmental Protection Agency (EPA) on August 18, 2004, for diffusion flame gas-fired turbines—the type of turbine proposed for the BBS SCCT project. The BBS SCCTs will be subject to the applicable requirements of New Source Performance Standard (NSPS) Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

Operation of the proposed BBS 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), 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.

Following this introduction, the revised air construction permit application package is organized as follows:

- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of New Source Review (NSR) procedures to the proposed project.
- Section 4.0 describes the applicable state and federal emission standards.

Appendices A and B provide the FDEP Application for Air Permit—Long Form and emission rate calculations, respectively. An analysis of PSD applicability is provided in Appendix C.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed new PWPS SCCTs will be located at the existing BBS. The BBS is located on Wyandotte Road in Apollo Beach, Hillsborough County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the BBS site location and nearby prominent geographical features.

The proposed BBS SCCT project consists of one PWPS FT8-3® SWIFTPAC® aeroderivative SCCT unit. The PWPS FT8-3® SWIFTPAC® unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 MW. The PWPS FT8-3® SCCTs will be fired primarily with pipeline-quality natural gas. ULSD fuel oil will serve as a back-up fuel source. The new SCCTs will operate in peaking service for no more than 3,500 hr/yr per SCCT, including no more than 500 hr/yr per SCCT of oil firing. Accordingly, maximum natural gas firing annual hours at rated load will range from 3,500 hr/yr (with no oil firing) to 3,000 hr/yr (with 500 hr/yr of oil firing). The new SCCTs will normally operate between 50- and 100-percent load. The SCCT project will also include one black start emergency diesel engine/generator set. Excluding emergency conditions, the diesel engine/generator set will only be operated for approximately 2 hours per week (100 hr/yr) each for routine testing and maintenance purposes. The emergency diesel engine will be fired with ULSD fuel oil.

Combustion of natural gas and ULSD fuel oil in the SCCTs, and ULSD fuel oil in the emergency diesel engine, will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, H_2SO_4 mist, and minor amounts of hazardous air pollutants (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 and ULSD fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Emissions from the emergency diesel engine will comply with the requirements of NSPS Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

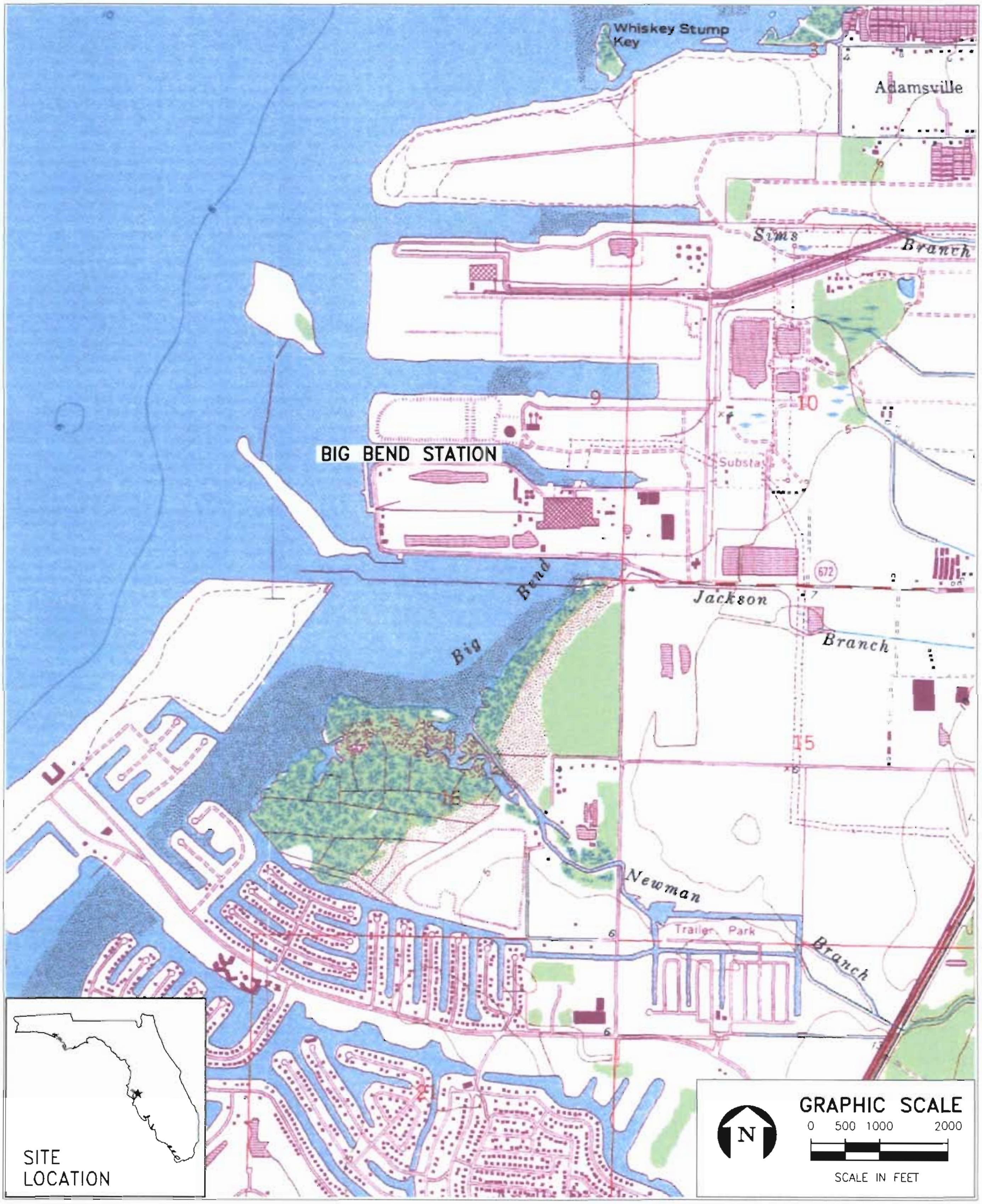

FIGURE 2-1.

BIG BEND STATION

LOCATION AND SURROUNDINGS

Source: USGS Quad: Gibsonton, FL, 1987; ECT, 2008.

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Figure 2-2 provides a site plan showing the BBS existing combustion units, major facility structures, and the proposed new SCCTs and emergency diesel engine. Additional details of the SCCTs are provided on Figure 2-3. Primary access to the BBS is from Wyandotte Road on the east side of the site. The BBS entrance has security to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed BBS SCCT project will include one nominal 62-MW PWPS FT8-3® SWIFTPAC® unit. 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 or ULSD fuel oil 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 fired with pipeline quality natural gas. Alternate operating modes include the use of ULSD fuel oil, 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, maximum SCCT natural gas firing annual hours at rated load will range from 3,500 hr/yr (with no oil firing) to 3,000 hr/yr (with 500 hr/yr of oil firing).

The aeroderivative SCCTs will use water injection to control NO_x emissions. The use of low-sulfur natural gas and ULSD fuel oil in the SCCTs will minimize PM/PM_{10}, SO_2,

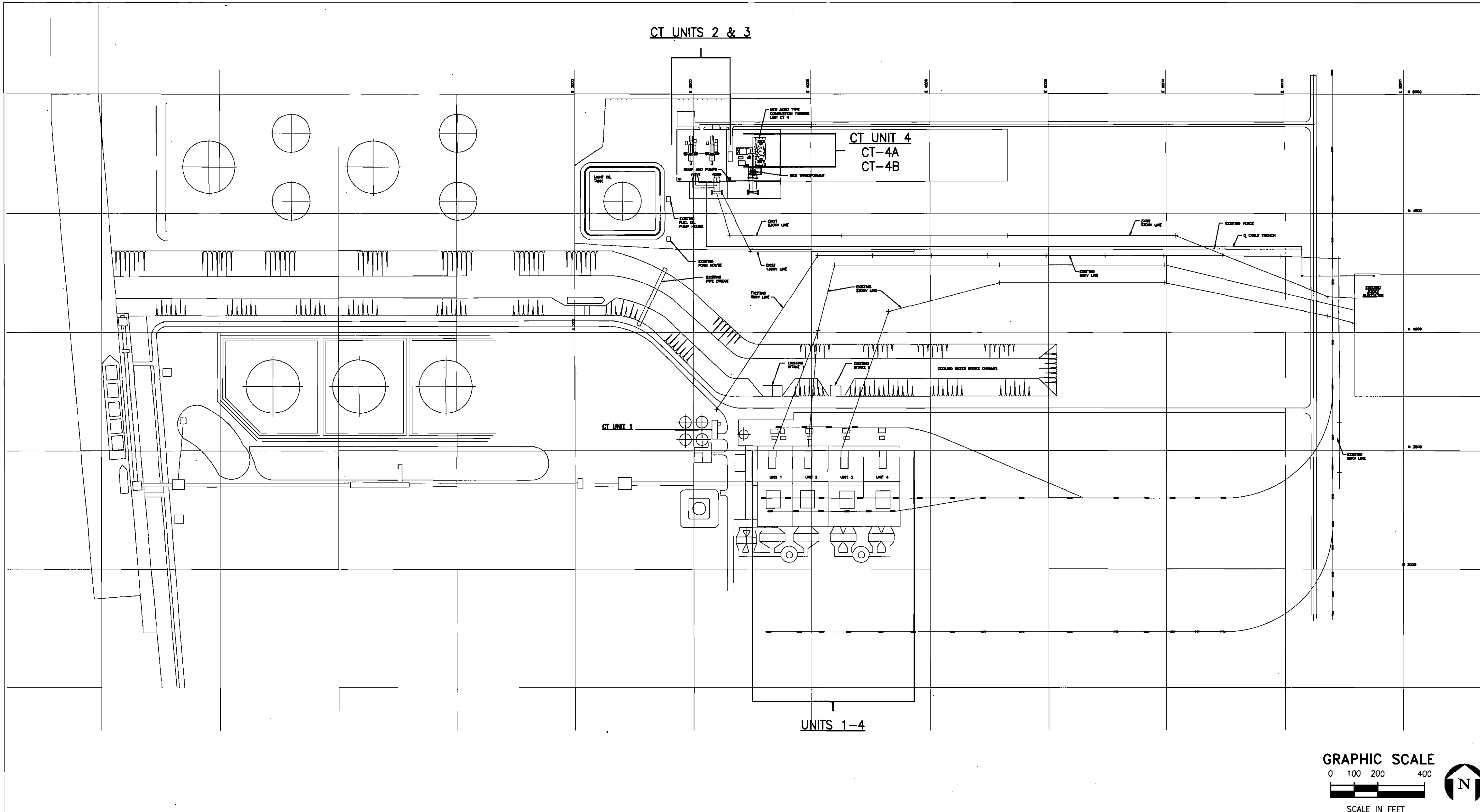

FIGURE 2-2.

BIG BEND STATION

UNITS 1-4, AND CT UNITS 1-4 PLOT PLAN

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

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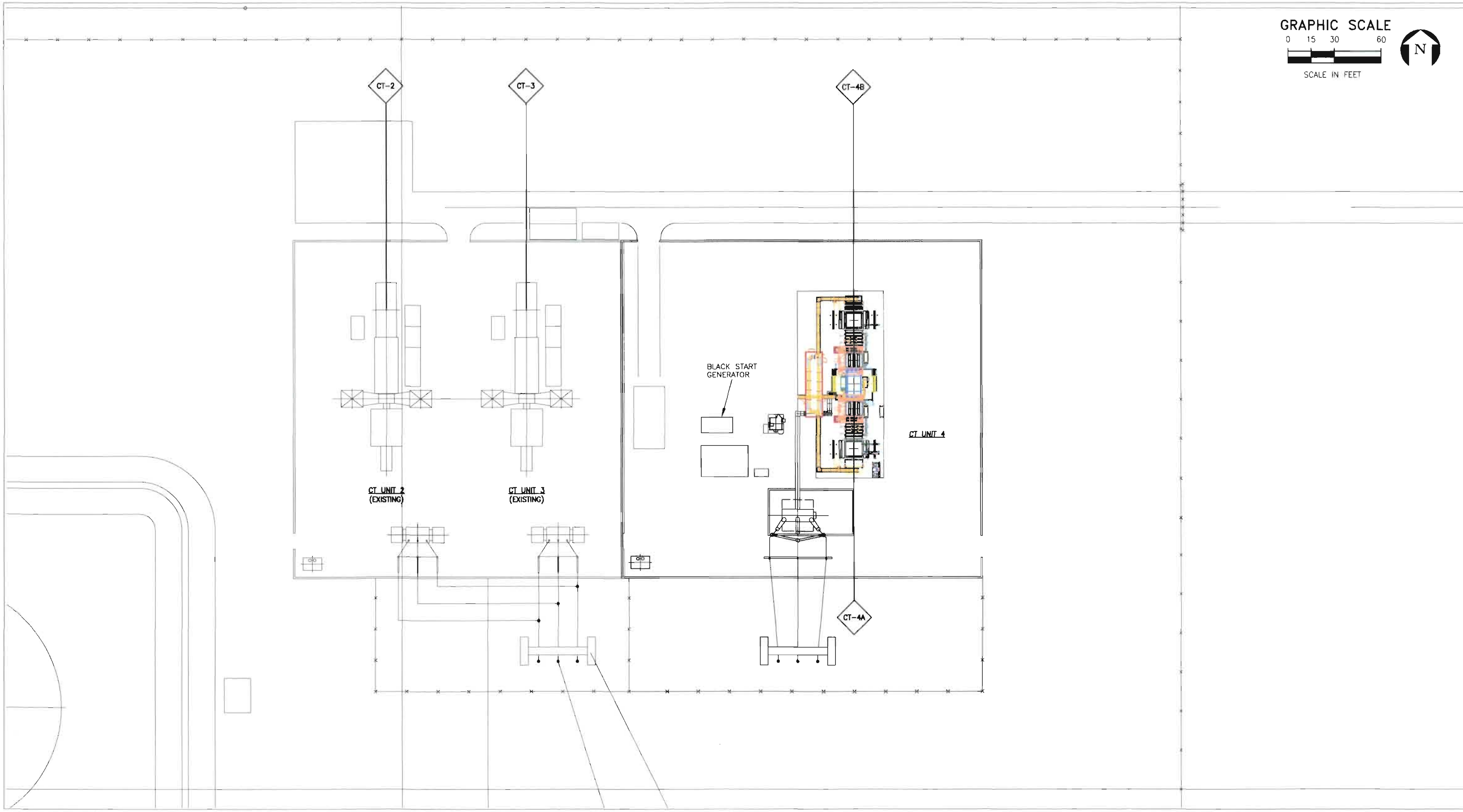

FIGURE 2-3.

BIG BEND STATION

CT UNITS 2-4 PLOT PLAN

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

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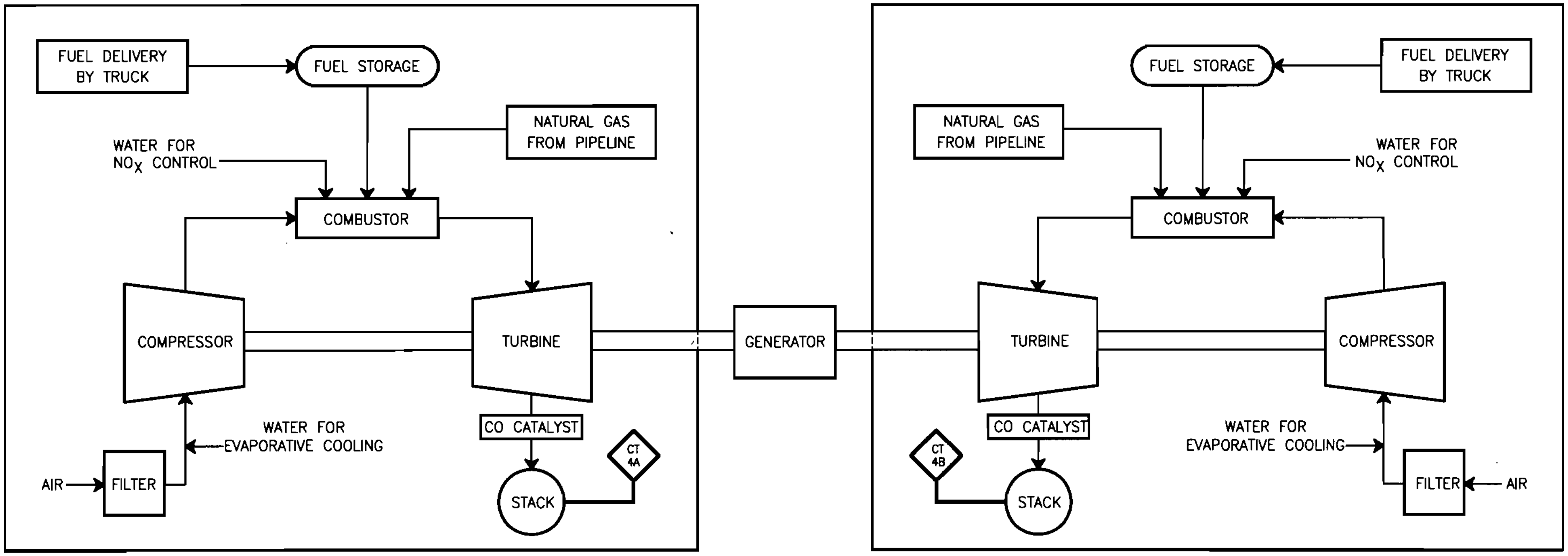

P&W FT8–3 SWIFT PAC SIMPLE CYCLE COMBUSTION TURBINE

FIGURE 2-4.
BBS----P&W SCCT PROCESS FLOW DIAGRAM

Source: ECT, 2008.

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and H_2SO_4 mist air emissions. Oxidation catalyst will be employed to control CO and VOC emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant emission rates for natural gas and ULSD fuel oil, respectively. H_2SO_4 mist SCCT emissions rates for natural gas and ULSD fuel oil are shown on Tables 2-3 and 2-4, respectively. Maximum hourly organic hazardous air pollutant emission rates for natural gas and ULSD fuel oil are provided on Tables 2-5 and 2-6, respectively. 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 and ULSD fuel oil.

Maximum hourly emissions rates, in units of pounds per hour (lb/hr), will generally occur during SCCT operations at summer ambient temperatures (i.e., 90°F), rated load, and ULSD fuel oil firing. Appendix B provides the bases for these emissions rates.

Table 2-7 presents projected maximum annualized criteria and noncriteria emissions for the BBS SCCT project. Two annual operating profiles were assessed. The first assumes base load operation with natural gas firing for 3,500 hr/yr at an ambient temperature of 59°F. The second annual profile assumes base load operation for 3,000 hr/yr (natural gas firing), base load operation for 500 hr/yr (fuel oil firing), and ambient temperatures of 59°F. Table 2-7 shows the highest annual emission rates for either profile. These profiles represent conservative estimates of annual emission rates since the annual average temperature for the Tampa Bay area is 72°F.

Tables 2-8 and 2-9 provide stack parameters for the SCCTs for natural gas and ULSD fuel oil, respectively. Stack parameters for the emergency diesel engine are shown in Table 2-10.

Table 2-1. Maximum Criteria Pollutant Emissions Rates for Three SCCT Loads and Three Ambient Temperatures—Natural Gas (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	1.87	0.24	31.6	3.98	6.2	0.77	1.3	0.16	Neg.	Neg.
	59†	2.5	0.32	1.89	0.24	32.0	4.03	4.7	0.59	1.4	0.17	Neg.	Neg.
	90†	2.5	0.32	1.79	0.23	30.2	3.81	4.4	0.56	1.3	0.16	Neg.	Neg.
75	20	2.5	0.32	1.45	0.18	24.4	3.07	8.4	1.05	2.7	0.33	Neg.	Neg.
	59†	2.5	0.32	1.47	0.19	24.8	3.12	7.0	0.89	1.9	0.24	Neg.	Neg.
	90†	2.5	0.32	1.41	0.18	23.7	2.99	5.4	0.68	1.3	0.16	Neg.	Neg.
50	20	2.5	0.32	1.06	0.13	18.2	2.29	9.1	1.15	5.1	0.64	Neg.	Neg.
	59†	2.5	0.32	1.08	0.14	18.2	2.29	6.6	0.83	2.2	0.27	Neg.	Neg.
	90†	2.5	0.32	1.04	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: PWPS, 2008.
ECT, 2008.

Table 2-2. Maximum Criteria Pollutant Emissions Rates for Three SCCT Loads and Three Ambient Temperatures—ULSD Fuel Oil (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	7.5	0.95	0.45	0.06	49.4	6.22	1.5	0.19	1.0	0.13	Neg.	Neg.
	59†	7.5	0.95	0.46	0.06	50.5	6.36	1.5	0.19	1.1	0.13	Neg.	Neg.
	90†	7.5	0.95	0.47	0.06	51.3	6.46	1.5	0.19	1.1	0.13	Neg.	Neg.
75	20	7.5	0.95	0.36	0.05	38.9	4.90	1.8	0.23	1.4	0.18	Neg.	Neg.
	59†	7.5	0.95	0.37	0.05	39.8	5.01	1.4	0.18	0.8	0.10	Neg.	Neg.
	90†	7.5	0.95	0.37	0.05	40.4	5.09	1.2	0.15	0.9	0.11	Neg.	Neg.
50	20	7.5	0.95	0.27	0.03	28.7	3.62	2.1	0.26	3.0	0.38	Neg.	Neg.
	59†	7.5	0.95	0.27	0.03	29.3	3.69	1.6	0.20	1.6	0.20	Neg.	Neg.
	90†	7.5	0.95	0.27	0.03	29.8	3.75	0.6	0.08	1.0	0.12	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: PWPS, 2008.
ECT, 2008.

Table 2-3. Maximum H_2SO_4 Mist Pollutant Emissions Rates for Three SCCT Loads and Three Ambient Temperatures—Natural Gas (per SCCT)

SCCT Load (%)	Ambient Temperature (°F)	H_2SO_4 Mist	
		lb/hr	g/s
100	20	0.21	0.027
	59*	0.22	0.027
	90*	0.21	0.026
75	20	0.17	0.021
	59*	0.17	0.021
	90*	0.16	0.020
50	20	0.12	0.015
	59*	0.12	0.016
	90*	0.12	0.015

Note: g/s = gram per second.

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

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

Table 2-4. Maximum H_2SO_4 Mist Pollutant Emissions Rates for Three SCCT Loads and Three Ambient Temperatures—ULSD Fuel Oil (per SCCT)

SCCT Load (%)	Ambient Temperature (°F)	H_2SO_4 Mist	
		lb/hr	g/s
100	20	0.052	0.0066
	59*	0.053	0.0067
	90*	0.054	0.0068
75	20	0.041	0.0052
	59*	0.042	0.0053
	90*	0.043	0.0054
50	20	0.030	0.0038
	59*	0.031	0.0039
	90*	0.032	0.0040

Note: g/s = gram per second.

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

Sources: ECT, 2008
PWPS, 2008.

Table 2-5. Maximum Organic HAP Emissions Rates for 100-Percent SCCT Load and Three Ambient Temperatures—Natural Gas (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	7.28E-05	9.17E-06	6.77E-03	8.53E-04	1.08E-03	1.37E-04	2.03E-03	2.56E-04	5.42E-03	6.83E-04	1.20E-01	1.51E-02
	59*	7.37E-05	9.28E-06	6.85E-03	8.64E-04	1.10E-03	1.38E-04	2.06E-03	2.59E-04	5.48E-03	6.91E-04	1.22E-01	1.53E-02
	90*	6.95E-05	8.76E-06	6.47E-03	8.15E-04	1.03E-03	1.30E-04	1.94E-03	2.44E-04	5.17E-03	6.52E-04	1.15E-01	1.45E-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	2.20E-04	2.77E-05	3.72E-04	4.69E-05	4.91E-03	6.19E-04	2.20E-02	2.77E-03	1.08E-02	1.37E-03
	59*	2.23E-04	2.81E-05	3.77E-04	4.75E-05	4.97E-03	6.26E-04	2.23E-02	2.81E-03	1.10E-02	1.38E-03
	90*	2.10E-04	2.65E-05	3.56E-04	4.48E-05	4.69E-03	5.91E-04	2.10E-02	2.65E-03	1.03E-02	1.30E-03

Note: Neg. = negligible

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

Source: ECT, 2008.

Table 2-6. Maximum Organic HAP Emissions Rates for 100-Percent SCCT Load and Three Ambient Temperatures—ULSD Fuel Oil SCCT)

SCCT Load (%)	Ambient Temperature (°F)	1,3-Butadiene		Arsenic		Cadmium		Benzene		Beryllium		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	2.37E-03	2.99E-04	3.26E-03	4.11E-04	1.42E-03	1.79E-04	8.15E-03	1.03E-03	9.18E-05	1.16E-05	5.18E-03	6.53E-04
	59*	2.42E-03	3.05E-04	3.33E-03	4.20E-04	1.45E-03	1.83E-04	8.33E-03	1.05E-03	9.38E-05	1.18E-05	5.30E-03	6.68E-04
	90*	2.46E-03	3.10E-04	3.38E-03	4.26E-04	1.48E-03	1.86E-04	8.46E-03	1.07E-03	9.53E-05	1.20E-05	5.38E-03	6.78E-04

SCCT Load (%)	Ambient Temperature (°F)	Naphthalene		Polycyclic Organic Matter		Manganese		Mercury		Nickel		Selenium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	5.18E-03	6.53E-04	5.92E-03	7.47E-04	8.33E-05	1.05E-05	3.55E-04	4.48E-05	4.38E-04	5.52E-05	2.88E-05	3.63E-06
	59*	5.30E-03	6.68E-04	6.05E-03	7.63E-04	8.52E-05	1.07E-05	3.63E-04	4.58E-05	4.47E-04	5.64E-05	2.94E-05	3.71E-06
	90*	5.38E-03	6.78E-04	6.15E-03	7.75E-04	8.65E-05	1.09E-05	3.69E-04	4.65E-05	4.55E-04	5.73E-05	2.99E-05	3.77E-06

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

Source: ECT, 2008.

Table 2-7. Maximum Annualized Emissions Rates (tpy)

Pollutant	SCCT Project†
NO_x	122.4
CO	16.5
PM/PM_{10}*	11.3
SO_2	6.6
VOC	4.7
H_2SO_4 mist	0.8
1,3-Butadiene	0.0014
Acetaldehyde	0.024
Acrolein	0.0038
Arsenic	0.0019
Benzene	0.010
Beryllium	0.000059
Cadmium	0.0018
Chromium	0.0033
Ethylbenzene	0.019
Formaldehyde	0.43
Lead	0.00062
Manganese	0.00045
Mercury	0.00044
Naphthalene	0.0033
Nickel	0.0025
PAHs	0.0042
Propylene oxide	0.017
Selenium	0.000039
Toluene	0.078
Xylene	0.039
Total HAPs	0.62

Note: PAH = polycyclic aromatic hydrocarbon.

†Maximum of Annual Profiles 1 and 2.
*Filterable and condensable particulate matter.

Sources: PWPS, 2008.
TEC, 2008.
ECT, 2008.

Table 2-8. Stack Parameters for Three SCCT Loads and Three Ambient Temperatures—Natural Gas (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	751	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	25.8	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	681	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: PWPS, 2008.
ECT, 2008.

Table 2-9. Stack Parameters for Three SCCT Loads and Three Ambient Temperatures—ULSD Fuel Oil (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	793	696	92.3	28.1	9.5	2.90
	59*	60.0	18.3	864	735	94.2	28.7	9.5	2.90
	90*	60.0	18.3	921	767	95.6	29.1	9.5	2.90
75	20	60.0	18.3	744	669	78.7	24.0	9.5	2.90
	59*	60.0	18.3	814	708	80.0	24.4	9.5	2.90
	90*	60.0	18.3	872	740	81.3	24.8	9.5	2.90
50	20	60.0	18.3	699	644	64.0	19.5	9.5	2.90
	59*	60.0	18.3	767	682	64.9	19.8	9.5	2.90
	90*	60.0	18.3	823	713	66.0	20.1	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: PWPS, 2008.
ECT, 2008.

Table 2-10. Stack Parameters for Emergency Generator Diesel Engine

Exhaust Parameter	Emergency Generator
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 national ambient air quality standards (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 ambient air quality standards (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. BBS 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 kilometer (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

BBS 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 BBS SCCT project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

An assessment of PSD applicability was conducted using the procedures specified in Rule 62-212.400(2), F.A.C.—this assessment is provided in Appendix C. Comparisons of the net change in 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, the net change in emissions for each pollutant is below the applicable PSD significant emission rate level. Accordingly, the BBS SCCT project is not subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Detailed potential emission rate estimates for the BBS SCCT project are provided in Appendix B.

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

Pollutant	Net Change In Annual Emissions* (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	-422.7	40	No
CO	16.5	100	No
PM	11.3	25	No
PM_{10}	11.3	15	No
SO_2	6.6	40	No
Ozone/VOC	4.7	40	No
Lead	0.00062	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not present	3	No
H_2SO_4 mist	0.8	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

* Emission rates shown for CO, PM/PM_{10}, SO_2, VOC, lead, and H_2SO_4 mist represent potential annual rates for the BBS SCCT project without consideration of netting.

Sources: Rule 62-210.200(279), F.A.C.
TEC, 2008.
PWPS, 2008.
ECT, 2008.

3.4 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 BBS 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 BBS SCCT project will include two SCCTs and one emergency generator diesel engine. The SCCTs and diesel engine 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 CTs 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 BBS SCCTs will operate in peaking service for no more than 3,500 hr/yr per SCCT, including no more than 500 hr/yr per SCCT of ULSD fuel oil firing. 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 for natural gas and 74 ppmvd at 15-percent oxygen or 3.6 lb/MWh gross energy output for ULSD fuel oil. 96 ppmvd at 15-percent oxygen or 4.7 lb/MWh gross energy output when operating at less than 75 percent of peak load for either natural gas or ULSD.

- $\underline{SO_2}$—0.90 lb/MWh gross energy output, or 0.060 pound per million British thermal units (lb/MMBtu).

The BBS 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 BBS emergency diesel generator CI ICE 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 BBS emergency diesel engine 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 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 BBS SCCT project.

NESHAP 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. Since the BBS SCCT project emergency generator engine has a site-rating more than 500 bhp, it will be subject to the requirements of Subpart ZZZZ. However, new RICE that operate exclusively as emergency units are subject only to initial notification requirements.

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 BBS 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 monitoring 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 BBS 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.

In a July 11, 2008 Opinion, the U.S. Court of Appeals for the District of Columbia Circuit addressed petitions regarding CAIR. The petitions challenged various CAIR provisions including: (a) use of a regional cap and trade program to prevent 8-hour ozone and $PM_{2.5}$ NAAQS exceedances, (b) CAIR Phase II compliance deadline of 2015, (c) air quality impact level used to determine a significant impact with respect to the $PM_{2.5}$ NAAQS, (d) CAIR SO_2 and NO_x budgets, including use of fuel adjustment factors in allocating NO_x allowances, (e) retirement of Acid Rain Program SO_2 allowances, (f) inclusion of Florida, Texas, and Minnesota in the CAIR program, and (g) CAIR Phase I deadline of 2009.

The Court ruled in favor of the petitioners on most issues. The Court upheld EPA with respect to the $PM_{2.5}$ significant air quality impact level, the inclusion of Florida and Texas in the CAIR program, and the 2009 Phase I deadline. However, the Court vacated CAIR in its entirety stating that EPA's approach of region-wide emissions caps was fundamentally flawed and that EPA must completely redo its CAIR analysis. The Court further ruled that the CAIR emissions trading program was unlawful. The Court also vacated EPA's CAIR Federal Implementation Plan (FIP). The Court remanded both CAIR and the associated FIP to EPA. The Court noted that the NO_x SIP Call program would remain in effect.

The Court Opinion will not go into effect until the court issues its mandate, which will officially vacate CAIR and direct EPA to take actions consistent with the Opinion. Typically, the court withholds its mandate until seven days after the deadline for the parties to file petitions for rehearing (i.e., August 25th for the CAIR Opinion). If a party petitions for rehearing in the D.C. Circuit or asks the Supreme Court to hear the case, the issuance of the mandate may be delayed even further. However, a party may also request that the Court accelerate issuance of the mandate which, if granted, would immediately implement the Court's decision. Such a request was recently made and granted with respect to the recent Clean Air Mercury Rule (CAMR) and the Delisting Rule Court Opinion.

4.5 CLEAN AIR MERCURY RULE

On March 15, 2005, EPA issued the final 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 were required to submit plans by November 17, 2006, that addressed the state electric generating units (EGU) mercury caps for 2010 and 2018 for EPA review and approval. The state plans provided 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 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 BBS 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 BBS 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 BBS SCCTs or emergency generator diesel engine. There are no VOC, NO_x, lead, and PM RACT requirements applicable to the BBS SCCT project. NSPS Subparts KKKK and IIII will be applicable to the BBS SCCTs and emergency generator diesel engine, respectively. With the exception of the NESHAP Subpart ZZZZ notification for the emergency generator diesel engine, there are no 40 CFR 61 or 40 CFR 63 NESHAPs applicable to the BBS SCCT project.

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

APPENDIX A

APPLICATION FOR AIR PERMIT—LONG FORM

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

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

- For 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: **Big Bend Station**	
3. Facility Identification Number: **0570039**	
4. Facility Location...: Street Address or Other Locator: **13031 Wyandotte Road** City: **Apollo Beach** County: **Hillsborough** Zip Code: **33572**	
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: 8/22/08	3. PSD Number (if applicable):
2. Project Number(s): 0570039-040-AC	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

Air construction permit application for one (1) Pratt & Whitney Power Systems (PWPS) FT8-3® SWIFTPAC® aeroderivative simple-cycle combustion turbine (SCCT) unit. The PWPS FT8-3® SWIFTPAC® unit is comprised of two SCCTs coupled to one common generator having a nominal gross generation capacity of 62 MW. The PWPS FT8-3® SWIFTPAC® SCCTs will be fired primarily with pipeline-quality natural gas. Ultra low sulfur diesel (ULSD) fuel oil will serve as a back-up fuel source. The new SCCTs will operate in peaking service for no more than 3,500 hours per year (hr/yr) per SCCT, including no more than 500 hr/yr per SCCT of oil firing. The PWPS FT8-3® SWIFTPAC® SCCTs will be located at the existing Big Bend Station (BBS) in Hillsborough County. A detailed description of the BBS 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
040	CT4A; PWPS FT8-3® SWIFTPAC® Simple-Cycle Combustion Turbine Unit (CT Unit 4)	AC1A	N/A
041	CT4B; PWPS FT8-3® SWIFTPAC® Simple-Cycle Combustion Turbine Unit (CT Unit 4)	AC1A	N/A
042	Emergency Generator Diesel Engine	AC1A	N/A

Application Processing Fee

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

Note: The TEC Big Bend Station has been issued FINAL Title V Permit 0570039-028-AV. An application processing fee is not required pursuant to Rule 62-213.205(4), 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: **Paul L. Carpinone** **Director, 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 – 4858** ext. Fax: **(813) 228 – 1308**
4.	Owner/Authorized Representative Email Address: **plcarpinone@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.* Paul L. Carpinone 8-21-08 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

APPLICATION INFORMATION

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address... Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **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.

Signature 8/18/08

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) **361.9** North (km) **3,075.0**		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: **Karen Zwolak, Senior Environmental Consultant**
2. Facility Contact Mailing Address... Organization/Firm: **Tampa Electric Company** Street Address: **P.O. Box 111** City: **Tampa** State: **Florida** Zip Code: **33601-0111**
3. Facility Contact Telephone Numbers: Telephone: **(813) 228-4111** ext. Fax: **(813) 228-1308**
4. Facility Contact Email Address: **kozwolak@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 Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 [40 CFR Part 60 Subpart Da] applies to Unit No. 4 Steam Generator (EU 004).

NSPS for Stationary Combustion Turbines [40 CFR Part 60 Subpart KKKK] will apply to the PWPS FT8-3® SWIFTPAC® simple-cycle combustion turbines (EU 040 and EU 041).

NSPS for Stationary Compression Ignition Internal Combustion Engines [40 CFR Part 60 Subpart IIII] will apply to the CT Unit 4 emergency generator diesel engine (EU 042).

NESHAPS for Shipbuilding and Ship Repair (Surface Coating) [40 CFR Part 63 Subpart II] applies to Surface Coating of Ships (EU 035).

NESHAPS for Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63 Subpart ZZZZ] will apply to the CT Unit 4 emergency generator diesel engine (EU 042).

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOX	**A**	**N**
SO2	**A**	**Y**
CO	**A**	**N**
PM10	**A**	**Y**
PM	**A**	**Y**
VOC	**A**	**N**
H106 (Hydrogen Chloride)	**A**	**N**
H107 (Hydrogen Fluoride)	**A**	**N**
H133 (Nickel Compounds)	**A**	**N**
HAPS (Total)	**A**	**N**

FACILITY INFORMATION

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
SO2	**N**	**001 - 004**		**71,810**	**ESCPSD**
PM/PM10	**N**	**001 - 004**		**2,767**	**ESCPSD**

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

Additional SO_2 caps for Units 001 – 003 are 31.5 ton/hr (3-hour average) and 25 ton/hr (24-hour block average). In addition, Units 001 and 002 are limited to 16.5 ton/hr SO_2 (24-hour block average).

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 2.0** ☐ 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: ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:_________ ☒ Not Applicable

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

Additional Requirements Comment

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:
   Aeroderivative simple cycle combustion turbine (SCCT) component of a PWPS FT8-3® SWIFTPAC® unit.

3. Emissions Unit Identification Number: **040 (CT Unit 4; CT4A)**

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 Power Systems** Model Number: **FT8-3® SWIFTPAC®**

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

11. Emissions Unit Comment:

    Unit 4 PWPS FT8-3® SWIFTPAC® is comprised of two identical simple cycle aeroderivative combustion turbines (CT-4A and CT-4B) 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: **342.7** million Btu/hr **(HHV)**		
4. Maximum Incineration Rate: pounds/hr tons/day		
5. Requested Maximum Operating Schedule:	hours/day weeks/year	days/week **3,500** hours/year
6. Operating Capacity/Schedule Comment: **Maximum heat input rate is for natural gas-firing at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Maximum heat input rate under the same operating conditions for ULSD fuel oil-firing is 302.7 MMBtu/hr. Heat input will vary with CT load, fuel type, and ambient conditions.** **The new SCCTs will operate in peaking service for no more than 3,500 hours per year (hr/yr) per SCCT, including no more than 500 hr/yr per SCCT of oil firing. Accordingly, maximum natural gas-firing annual hours at rated load will range from 3,500 hr/yr (with no oil firing) to 3,000 hr/yr (with 500 hr/yr of oil firing).**		

C. EMISSION POINT (STACK/VENT) INFORMATION

(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **4A**		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 for natural gas-firing 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, fuel type, and ambient conditions.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Pipeline quality natural gas burned in CT4A.**		
2. Source Classification Code (SCC): **2-01-002-02**	3. SCC Units: **Million cubic feet burned**	
4. Maximum Hourly Rate: **0.332**	5. Maximum Annual Rate: **1,162**	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 3,500 hrs/yr/CT.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **ULSD fuel oil burned in CT4A.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousands Gallons Used**	
4. Maximum Hourly Rate: **2.27**	5. Maximum Annual Rate: **1,135**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.0015**	8. Maximum % Ash: **0.10**	9. Million Btu per SCC Unit: **133.1 (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 500 hrs/yr/CT.**		

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)** **51.3** lb/hour **60.9** 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 (PWPS) 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 ULSD fuel oil at 100% load with evaporative cooling, 90°F ambient temperature, and 79°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,000 hrs/yr/CT (natural gas) and 500 hrs/yr/CT (ULSD fuel oil).

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 **2** **(Per CT)**

1. Basis for Allowable Emissions Code: **ESCPSD**	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 **56.0** tons/year
5. Method of Compliance: **EPA Reference Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Also subject to NSPS Subpart KKKK NO_x emission standard.** **Allowable and equivalent allowable emissions are for natural gas-firing 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 3,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions **2** of **2** **(Per CT)**

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **51.3** lb/hour **12.9** tons/year
5. Method of Compliance: **EPA Reference Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Also subject to NSPS Subpart KKKK NO_x emission standard.** **Allowable and equivalent hourly allowable emissions are for ULSD fuel oil-firing at 100% load with evaporative cooling, 90°F ambient temperature, and 79°F CT compressor inlet temperature per CT. Equivalent allowable annual emission rate based on 500 hrs/yr/CT at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature.**	

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 **8.3** 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 (PWPS) 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 natural gas at 50% load and 20°F ambient temperature per CT.

Potential annual emission rate based on natural gas at 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,500 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 2 (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 **8.3** 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 for natural gas-firing at 50% load and 20°F ambient temperature per CT.** **Equivalent allowable annual emission rate based on natural gas firing at 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions 2 of 2 (Per CT)

1. Basis for Allowable Emissions Code: **ESCPSD**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **5.1 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **2.1** lb/hour **0.4** tons/year
5. Method of Compliance: **EPA Reference Method 7E**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable and equivalent hourly allowable emissions are for ULSD fuel oil-firing at 50% load and 20°F ambient temperature per CT. Equivalent allowable annual emission rate based on 500 hrs/yr/CT at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature.**	

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)** **7.5** lb/hour **5.7** 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 (PWPS) 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 ULSD fuel oil at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,000 hrs/yr/CT (natural gas) and 500 hrs/yr/CT (ULSD fuel oil).

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.

<u>Allowable Emissions</u> 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: **10% opacity (surrogate for PM/PM_{10})**	4. Equivalent Allowable Emissions: **7.5** lb/hour **5.7** tons/year
5. Method of Compliance: **EPA Reference Method 9**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions are for both natural gas and ULSD fuel oil.** **Equivalent hourly allowable emissions are for ULSD fuel oil-firing at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT. Equivalent annual allowable emission rate based on 3,000 hrs/yr/CT (natural gas) and 500 hrs/yr/CT (ULSD fuel oil).**	

<u>Allowable Emissions</u> 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 **3.3** 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 natural gas at 100% load with evaporative cooling, 59°F ambient temperature, and 52°F CT compressor inlet temperature per CT.

Potential annual emission rate based on 3,500 hrs/yr/CT (natural gas).

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 **2 (Per CT)**

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 **3.3** 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 NSPS Subpart KKKK SO_2 emission standard.** **Allowable and equivalent allowable emissions are for natural gas-firing 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 3,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions **2** of **2 (Per CT)**

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0015 weight percent S fuel oil**	4. Equivalent Allowable Emissions: **0.5** lb/hour **0.1** 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 NSPS Subpart KKKK SO_2 emission standard.** **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 500 hrs/yr/CT.**	

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 **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 (PWPS) 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 natural gas at 50% load and 20°F ambient temperature.

Potential annual emission rates based on natural gas at 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,500 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 **2** **(Per CT)**

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 **2.4** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable and equivalent allowable hourly emissions are for natural gas-firing at 50% load and 20°F ambient temperature per CT.** **Equivalent allowable annual emission rate based on natural gas-firing at 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 3,500 hrs/yr/CT.**	

Allowable Emissions Allowable Emissions **2** of **2** **(Per CT)**

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: **3.0** lb/hour **0.3** tons/year
5. Method of Compliance: **N/A**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable and equivalent allowable hourly emissions are for ULSD fuel oil-firing at 50% load and 20°F ambient temperature per CT.** **Equivalent allowable annual emission rate based on ULSD fuel oil-firing at 100% load with evaporative cooling, 59°F ambient temperature, 52°F CT compressor inlet temperature, and 500 hrs/yr/CT.**	

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: **Voluntary limit.**	

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), F.A.C.**	

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 **4**

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).** **Monitor information will be provided to the Department when available.**	

Continuous Monitoring System: Continuous Monitor **2** of **4**

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).** **Monitor information will be provided to the Department when available.**	

H. CONTINUOUS MONITOR INFORMATION (CONTINUED)

Continuous Monitoring System: Continuous Monitor **3** of **4**

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Monitor information will be provided to the Department when available.**	

Continuous Monitoring System: Continuous Monitor **4** of **4**

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).** **Monitor information will be provided to the Department when available.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **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 2.0** ☐ 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 2.0** ☐ 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: ☒ Not Applicable	
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID: ☒ Not Applicable	
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID: **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 Units 040 and 041 (Unit 4 – CT4A and CT4B) are identical emission units.

Section III. Emissions Unit Information provided for EU-040 (Unit 4 – CT4A) is also applicable to EU-041 (Unit 4 – CT4B).

Emissions Unit Information Sections 2 through 8 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: **042**

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: **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 CT Unit 4 in the event of power interruption from the grid.

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

Emissions Unit Control Equipment/Method: Control **1** of **1**

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

Emissions Unit Control Equipment/Method: Control of

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

Emissions Unit Control Equipment/Method: Control __ of __

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

Emissions Unit Control Equipment/Method: Control __ of __

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

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **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.

<u>Allowable Emissions</u> 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.**	

<u>Allowable Emissions</u> 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), F.A.C.**	

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 2.0** ☐ 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 2.0** ☐ 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:	☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rules 62-212.400(4)(d) and 62-212.500(4)(f), F.A.C.): ☐ Attached, Document ID:	☒ Not Applicable
3. Description of Stack Sampling Facilities: (Required for proposed new stack sampling facilities only) ☐ Attached, Document ID:	☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

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

ATTACHMENT 1

ACID RAIN PART APPLICATION

Acid Rain Part Application

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

This submission is: ☐ New ■ Revised ☐ Renewal

STEP 1

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

Big Bend Station	**Florida**	**0645**
Plant name	State	ORIS/Plant Code

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

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

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

a	b	c	d	e
Unit ID#	SO_2 Opt-in Unit? (Yes or No)	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	New or SO_2 Opt-in Units Commence Operation Date	New or SO_2 Opt-in Units Monitor Certification Deadline
BB01	**No**	**Yes**	**N/A**	**N/A**
BB02	**No**	**Yes**	**N/A**	**N/A**
BB03	**No**	**Yes**	**N/A**	**N/A**
BB04	**No**	**Yes**	**N/A**	**N/A**
CT4A	**No**	**Yes**	**N/A**	**N/A**
CT4B	**No**	**Yes**	**N/A**	**N/A**
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		
		Yes		

Big Bend Station

Plant Name (from STEP 1)

STEP 3

Read the standard requirements.

Acid Rain Part Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

Nitrogen Oxides Requirements.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Big Bend Station
Plant Name (from STEP 1)

EP 3, Continued.

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

Effect on Other Authorities.

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

STEP 4
For SO_2 Opt-in units only.

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

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

In column "h" enter the hours.

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

Big Bend Station

Plant Name (from STEP 1)

STEP 5

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

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

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

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

STEP 6

For SO_2 Opt-in units only.

Attach additional requirements, certify and sign.

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

Signature	Date

STEP 7

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

Certification (for designated representative or alternate designated representative only)

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

Byron T. Burrows Name	**Manager, Air Programs** Title
Tampa Electric Company Owner Company Name	
(813) 228-1282 Phone	**btburrows@tecoenergy.com** E-mail address
Signature [signature]	Date 8/20/08

ATTACHMENT 2

CLEAN AIR INTERSTATE RULE (CAIR) APPLICATION

Clean Air Interstate Rule (CAIR) Part

For more information, see instructions and refer to 40 CFR 96.121, 96.122, 96.221, 96.222, 96.321 and 96.322; and Rule 62-296.470, F.A.C.

This submission is: ☐ New ■ Revised ☐ Renewal

STEP 1

Identify the source by plant name and ORIS or EIA plant code

Plant Name:	State:	ORIS or EIA Plant Code:
Big Bend Station	**Florida**	**0645**

STEP 2

In column "a" enter the unit ID# for every CAIR unit at the CAIR source.

In columns "b," "c," and "d," indicate to which CAIR program(s) each unit is subject by placing an "X" in the column(s).

For new units, enter the requested information in columns "e" and "f.

a	b	c	d	e	f
Unit ID#	Unit will hold nitrogen oxides (NO_X) allowances in accordance with 40 CFR 96.106(c)(1)	Unit will hold sulfur dioxide (SO_2) allowances in accordance with 40 CFR 96.206(c)(1)	Unit will hold NO_X Ozone Season allowances in accordance with 40 CFR 96.306(c)(1)	New Units Expected Commence Commercial Operation Date	New Units Expected Monitor Certification Deadline
BB01	**Yes**	**Yes**	**Yes**		
BB02	**Yes**	**Yes**	**Yes**		
BB03	**Yes**	**Yes**	**Yes**		
BB04	**Yes**	**Yes**	**Yes**		
CT4A	**Yes**	**Yes**	**Yes**	**5/15/09**	**8/15/09**
CT4B	**Yes**	**Yes**	**Yes**	**5/15/09**	**8/15/09**

STEP 3

Read the standard requirements.

Plant Name (from STEP 1) **Big Bend Station**

CAIR NO_X ANNUAL TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_X source and each CAIR NO_X unit at the source shall:
(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.122 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
(ii) [Reserved];
(2) The owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CC, and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source and each CAIR NO_X unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH, shall be used to determine compliance by each CAIR NO_X source with the following CAIR NO_X Emissions Requirements.

NO_X Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 40 CFR 96.154(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 40 CFR Part 96, Subpart HH.
(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (1) of the NO_X Requirements starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.170(b)(1) or (2) and for each control period thereafter.
(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Requirements, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.
(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FF and GG.
(5) A CAIR NO_X allowance is a limited authorization to emit one ton of NO_X in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR Part, or an exemption under 40 CFR 96.105 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NO_X allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EE, FF, or GG, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_X unit.

Excess Emissions Requirements.

If a CAIR NO_X source emits NO_X during any control period in excess of the CAIR NO_X emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under 40 CFR 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the DEP or the Administrator.
(i) The certificate of representation under 40 CFR 96.113 for the CAIR designated representative for the source and each CAIR NO_X unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program.
(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_X Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program.
(2) The CAIR designated representative of a CAIR NO_X source and each CAIR NO_X unit at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, including those under 40 CFR Part 96, Subpart HH.

Plant Name (from STEP 1) **Big Bend Station**

STEP 3, Continued

Liability.

(1) Each CAIR NO_X source and each CAIR NO_X unit shall meet the requirements of the CAIR NO_X Annual Trading Program.
(2) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X source or the CAIR designated representative of a CAIR NO_X source shall also apply to the owners and operators of such source and of the CAIR NO_X units at the source.
(3) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X unit or the CAIR designated representative of a CAIR NO_X unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_X Annual Trading Program, a CAIR Part, or an exemption under 40 CFR 96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source or CAIR NO_X unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR SO_2 TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall:
 (i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.222 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and
 (ii) [Reserved];
(2) The owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall have a CAIR Part included in the Title V operating permit issued by the DEP under 40 CFR Part 96, Subpart CCC, for the source and operate the source and each CAIR unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR SO_2 source and each SO_2 CAIR unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96 ,Subpart HHH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH, shall be used to determine compliance by each CAIR SO_2 source with the following CAIR SO_2 Emission Requirements.

SO_2 Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO_2 allowances available for compliance deductions for the control period, as determined in accordance with 40 CFR 96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHH.
(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (1) of the Sulfur Dioxide Emission Requirements starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.270(b)(1) or (2) and for each control period thereafter.
(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the SO_2 Emission Requirements, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.
(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFF and GGG.
(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR Part, or an exemption under 40 CFR 96.205 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR SO_2 allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or GGG, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR SO_2 unit.

Excess Emissions Requirements.

If a CAIR SO_2 source emits SO_2 during any control period in excess of the CAIR SO_2 emissions limitation, then:
(1) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under 40 CFR 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable state law.

Plant Name (from STEP 1) **Big Bend Station**

STEP 3, Continued

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Department or the Administrator.

(i) The certificate of representation under 40 CFR 96.213 for the CAIR designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO_2 Trading Program.

(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO_2 Trading Program.

(2) The CAIR designated representative of a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR SO_2 Trading Program, including those under 40 CFR Part 96, Subpart HHH.

Liability.

(1) Each CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program.
(2) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 source or the CAIR designated representative of a CAIR SO_2 source shall also apply to the owners and operators of such source and of the CAIR SO_2 units at the source.
(3) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 unit or the CAIR designated representative of a CAIR SO_2 unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR SO_2 Trading Program, a CAIR Part, or an exemption under 40 CFR 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

CAIR NO_x OZONE SEASON TRADING PROGRAM

CAIR Part Requirements.

(1) The CAIR designated representative of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall:

(i) Submit to the DEP a complete and certified CAIR Part form under 40 CFR 96.322 and Rule 62-296.470, F.A.C., in accordance with the deadlines specified in Rule 62-213.420, F.A.C.; and

(ii) [Reserved];

(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a Title V operating permit or air construction permit, and each CAIR NO_X Ozone Season unit required to have a Title V operating permit or air construction permit at the source shall have a CAIR Part included in the Title V operating permit or air construction permit issued by the DEP under 40 CFR Part 96, Subpart CCCC, for the source and operate the source and the unit in compliance with such CAIR Part.

Monitoring, Reporting, and Recordkeeping Requirements.

(1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR Part 96, Subpart HHHH, and Rule 62-296.470, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHHH, shall be used to determine compliance by each CAIR NO_X Ozone Season source with the following CAIR NO_X Ozone Season Emissions Requirements.

NO_X Ozone Season Emission Requirements.

(1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under 40 CFR 96.354(a) in an amount not less than the tons of total NO_X emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with 40 CFR Part 96, Subpart HHHH.
(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (1) of the NO, Ozone Season Emission Requirements starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 96.370(b)(1),(2), or (3) and for each control period thereafter.
(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (1) of the NO_X Ozone Season Emission Requirements, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.
(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with 40 CFR Part 96, Subparts FFFF and GGGG.
(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of NO_X in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR Part, or an exemption under 40 CFR 96.305 and no

(5) A CAIR NO_x Ozone Season allowance is a limited authorization to emit one ton of NO_x in accordance with the CAIR NO_x Ozone Season Trading Program. No provision of the CAIR NO_x Ozone Season Trading Program, the CAIR Part, or an exemption under 40 CFR 96.305 and no provision of law shall be construed to limit the authority of the state or the United States to terminate or limit such authorization.
(6) A CAIR NO_x Ozone Season allowance does not constitute a property right.
(7) Upon recordation by the Administrator under 40 CFR Part 96, Subpart EEEE, FFFF or GGGG, every allocation, transfer, or deduction of a CAIR NO_x Ozone Season allowance to or from a CAIR NO_x Ozone Season unit's compliance account is incorporated automatically in any CAIR Part of the source that includes the CAIR NO_x Ozone Season unit.

Plant Name (from STEP 1) **Big Bend Station**

STEP 3, Continued

Excess Emissions Requirements.

If a CAIR NO_x Ozone Season source emits NO_x during any control period in excess of the CAIR NO_x Ozone Season emissions limitation, then:
(1) The owners and operators of the source and each CAIR NO_x Ozone Season unit at the source shall surrender the CAIR NO_x Ozone Season allowances required for deduction under 40 CFR 96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable state law; and
(2) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAAA, the Clean Air Act, and applicable state law.

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the DEP or the Administrator.
(i) The certificate of representation under 40 CFR 96.313 for the CAIR designated representative for the source and each CAIR NO_x Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR 96.113 changing the CAIR designated representative.
(ii) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HHHH, of this part, provided that to the extent that 40 CFR Part 96, Subpart HHHH, provides for a 3-year period for recordkeeping, the 3-year period shall apply.
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Ozone Season Trading Program.
(iv) Copies of all documents used to complete a CAIR Part form and any other submission under the CAIR NO_x Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_x Ozone Season Trading Program.
(2) The CAIR designated representative of a CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit at the source shall submit the reports required under the CAIR NO_x Ozone Season Trading Program, including those under 40 CFR Part 96, Subpart HHHH.

Liability.

(1) Each CAIR NO_x Ozone Season source and each CAIR NO_x Ozone Season unit shall meet the requirements of the CAIR NO_x Ozone Season Trading Program.
(2) Any provision of the CAIR NO_x Ozone Season Trading Program that applies to a CAIR NO_x Ozone Season source or the CAIR designated representative of a CAIR NO_x Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_x Ozone Season units at the source.
(3) Any provision of the CAIR NO_x Ozone Season Trading Program that applies to a CAIR NO_x Ozone Season unit or the CAIR designated representative of a CAIR NO_x Ozone Season unit shall also apply to the owners and operators of such unit.

Effect on Other Authorities.

No provision of the CAIR NO_x Ozone Season Trading Program, a CAIR Part, or an exemption under 40 CFR 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x Ozone Season source or CAIR NO_x Ozone Season unit from compliance with any other provision of the applicable, approved State Implementation Plan, a federally enforceable permit, or the Clean Air Act.

STEP 4

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

Certification (for designated representative or alternate designated representative only)

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

Byron T. Burrows Name	**Manager, Air Programs** Title
Tampa Electric Company Owner Company Name	
(813) 228-1282 Phone	**btburrows@tecoenergy.com** E-mail address
Signature	Date 8/20/08

APPENDIX B

EMISSION RATE CALCULATIONS

Appendix B - TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
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 Pb 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 Hazardous Air Pollutant Hourly Emission Rates - Natural Gas (Per CT)
B-6	CT PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Hourly Emission Rates - ULSD (Per CT)
B-7	CT NO_x, CO, VOC, and NH_3 Hourly Emission Rates - ULSD (Per CT)
B-8	CT Hazardous Air Pollutant Hourly Emission Rates - ULSD (Per CT)
B-9	CT Hazardous Air Pollutant Annual Emission Rates
B-10	CT Criteria Pollutant, H_2SO_4 Mist, and NH_3 Annual Emission Rates - Annual Profile 1
B-11	CT Criteria Pollutant, H_2SO_4 Mist, and NH_3 Annual Emission Rates - Annual Profile 2
B-12	CT Exhaust Flow Rates - Natural Gas (Per CT)
B-13	CT Fuel Flow Rates - Natural Gas (Per CT)
B-14	CT Exhaust Flow Rates - ULSD (Per CT)
B-15	CT Fuel Flow Rates - ULSD (Per CT)
B-16	Emergency Diesel Engine Emission Rates - Criteria Pollutant Pollutants
B-17	Emergency Diesel Engine Emission Rates - Hazardous Air Pollutants
	Stack Parameters
B-18	CT - Natural Gas (Per CT)
B-19	CT - ULSD (Per CT)
B-20	Emergency Diesel Engine

ULSD - ultra low sulfur diesel fuel oil.

Source: ECT, 2008.

Table B-1. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Annual Emission Rate Summary

Pollutant	Potential Annual Emissions (ton/yr)		
	PWPS CTs (2 CTs) [1]	*Emergency Diesel Engine*	*Project Totals*
Criteria Pollutants			
NO_x	121.7	0.8	***122.4***
CO	16.5	0.034	***16.5***
VOC	4.7	0.0044	***4.7***
SO_2	6.6	0.00061	***6.6***
PM_{10} (filterable + condensable)	11.3	0.0035	***11.3***
Pb	0.0006	Neg.	***0.00062***
Hazardous Air Pollutants			
Formaldhyde[1]	0.4	Neg.	***0.4***
Total HAPs	0.6	Neg.	***0.6***
Other Pollutants			
H_2SO_4 Mist	0.8	Neg.	***0.8***
PM (filterable)[2]	11.3	0.0035	***11.3***
Other Constituents			
CO_2	136,865	65	***136,930***

N/A - not applicable
Neg. - negligible

[1] Maximum of Annual Profile 1 (3,500 hrs/yr/CT natural gas)
or Annual Profile 2 (3,000 hrs/yr/CT natural gas + 500 hrs/yr/CT ULSD fuel oil).
[2] Maximum individual HAP.
[3] For PWPS CTs, all PM is $PM_{2.5}$ or less. PM (filterable) is assumed to be 50% of total PM.

Sources: ECT, 2008.
PWPS, 2008.
TEC, 2008.

Table B-2. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Operating Scenarios - PWPS FT8-3 SwiftPac® Unit

Case	Ambient Temperature (°F)	CT Compressor Inlet Temperature (°F)	Load (%)	Evaporative Cooling	Natural Gas Firing	ULSD Fuel Oil Firing	Annual Profile #1 (hrs/yr)	Annual Profile #2 (hrs/yr)
1-G, 1-O	20	20	100		X	X		
2-G, 2-O	20	20	75		X	X		
3-G, 3-O	20	20	50		X	X		
4-G, 4-O	59	52	100	X	X	X	3,500	3,000 / 500
5-G, 5-O	59	52	75	X	X	X		
6-G, 6-O	59	52	50	X	X	X		
7-G, 7-O	90	79	100	X	X	X		
8-G, 8-O	90	79	75	X	X	X		
9-G, 9-O	90	79	50	X	X	X		

Note: FT8-3 SwiftPac® Unit consists of two combustion turbines and one common generator.

Sources: ECT, 2008.
PWPS, 2008.
TEC, 2008.

Table B-3. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case	Load (%)	PM/PM_{10}[1] (lb/hr)	PM/PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1-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% 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: ECT, 2008.
P&W, 2008.

Table B-4. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly NO_x, CO, AND VOC Emission Rates (Per CT) - Natural Gas

Temp. (°F)	Case	Load (%)	NO_x			CO			VOC[1,2]		
			(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)	(ppmvd)[3]	(lb/hr)	(g/sec)
20	1-Gas	100	25	31.6	3.98	8.0	6.2	0.78	3.0	1.3	0.16
	2-Gas	75	25	24.4	3.07	14.1	8.4	1.06	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	0.88	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	0.55	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% control for oxidation catalyst.

[2] Expressed as methane.

[3] Corrected to 15% O_2.

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

Table B-5. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hazardous Air Pollutant 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)	338.6	261.9	192.6	342.7	265.7	195.2	323.3	254.5	187.6

Hazardous Air Pollutant	Gas Emission Factor[1-4]	Hourly Emissions								
		1-G	2-G	3-G	4-G	5-G	6-G	7-G	8-G	9-G
	(lb/10^6 Btu)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
1,3-Butadiene	2.15E-07	7.28E-05	5.63E-05	4.14E-05	7.37E-05	5.71E-05	4.20E-05	6.95E-05	5.47E-05	4.03E-05
Acetaldehyde	2.00E-05	6.77E-03	5.24E-03	3.85E-03	6.85E-03	5.31E-03	3.90E-03	6.47E-03	5.09E-03	3.75E-03
Acrolein	3.20E-06	1.08E-03	8.38E-04	6.16E-04	1.10E-03	8.50E-04	6.25E-04	1.03E-03	8.14E-04	6.00E-04
Arsenic (As)	1.96E-07	6.64E-05	5.14E-05	3.78E-05	6.72E-05	5.21E-05	3.83E-05	6.34E-05	4.99E-05	3.68E-05
Benzene	6.00E-06	2.03E-03	1.57E-03	1.16E-03	2.06E-03	1.59E-03	1.17E-03	1.94E-03	1.53E-03	1.13E-03
Beryllium (Be)	1.18E-08	3.98E-06	3.08E-06	2.27E-06	4.03E-06	3.13E-06	2.30E-06	3.80E-06	2.99E-06	2.21E-06
Cadmium (Cd)	1.08E-06	3.65E-04	2.82E-04	2.08E-04	3.70E-04	2.87E-04	2.10E-04	3.49E-04	2.74E-04	2.02E-04
Chromium (Cr)	1.37E-06	4.65E-04	3.59E-04	2.64E-04	4.70E-04	3.65E-04	2.68E-04	4.44E-04	3.49E-04	2.58E-04
Ethylbenzene	1.60E-05	5.42E-03	4.19E-03	3.08E-03	5.48E-03	4.25E-03	3.12E-03	5.17E-03	4.07E-03	3.00E-03
Formaldehyde	3.55E-04	1.20E-01	9.30E-02	6.84E-02	1.22E-01	9.43E-02	6.93E-02	1.15E-01	9.03E-02	6.66E-02
Lead (Pb)	4.90E-07	1.66E-04	1.28E-04	9.44E-05	1.68E-04	1.30E-04	9.57E-05	1.59E-04	1.25E-04	9.20E-05
Manganese (Mn)	3.73E-07	1.26E-04	9.76E-05	7.17E-05	1.28E-04	9.90E-05	7.27E-05	1.20E-04	9.48E-05	6.99E-05
Mercury (Hg)	2.55E-07	8.63E-05	6.68E-05	4.91E-05	8.74E-05	6.77E-05	4.98E-05	8.24E-05	6.49E-05	4.78E-05
Naphthalene	6.50E-07	2.20E-04	1.70E-04	1.25E-04	2.23E-04	1.73E-04	1.27E-04	2.10E-04	1.65E-04	1.22E-04
Nickel (Ni)	2.06E-06	6.97E-04	5.39E-04	3.96E-04	7.06E-04	5.47E-04	4.02E-04	6.66E-04	5.24E-04	3.86E-04
Polycyclic Aromatic Hydrocarbons	1.10E-06	3.72E-04	2.88E-04	2.12E-04	3.77E-04	2.92E-04	2.15E-04	3.56E-04	2.80E-04	2.06E-04
Propylene Oxide	1.45E-05	4.91E-03	3.80E-03	2.79E-03	4.97E-03	3.85E-03	2.83E-03	4.69E-03	3.69E-03	2.72E-03
Selenium (Se)	2.35E-08	7.97E-06	6.16E-06	4.53E-06	8.06E-06	6.25E-06	4.59E-06	7.61E-06	5.99E-06	4.42E-06
Toluene	6.50E-05	2.20E-02	1.70E-02	1.25E-02	2.23E-02	1.73E-02	1.27E-02	2.10E-02	1.65E-02	1.22E-02
Xylene	3.20E-05	1.08E-02	8.38E-03	6.16E-03	1.10E-02	8.50E-03	6.25E-03	1.03E-02	8.14E-03	6.00E-03
Maximum Individual HAP		**0.120**	**0.093**	**0.068**	**0.122**	**0.094**	**0.069**	**0.115**	**0.090**	**0.067**
Total HAPs		**0.176**	**0.136**	**0.100**	**0.178**	**0.138**	**0.101**	**0.168**	**0.132**	**0.097**

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: ECT, 2008.
PWPS, 2008.

Table B-6. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly PM/PM_{10}, SO_2, H_2SO_4 Mist, and Pb Emission Rates (Per CT) - ULSD Fuel Oil

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1]		SO_2 [2]		H_2SO_4 [3]		Lead [4]	
			(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)	(lb/hr)	(g/sec)
20	1-Oil	100	7.5	0.95	0.45	0.06	0.052	0.0066	0.00023	0.000029
	2-Oil	75	7.5	0.95	0.36	0.05	0.041	0.0052	0.00018	0.000023
	3-Oil	50	7.5	0.95	0.27	0.03	0.030	0.0038	0.00013	0.000017
59	4-Oil	100	7.5	0.95	0.46	0.06	0.053	0.0067	0.00023	0.000029
	5-Oil	75	7.5	0.95	0.37	0.05	0.042	0.0053	0.00018	0.000023
	6-Oil	50	7.5	0.95	0.27	0.03	0.031	0.0039	0.00014	0.000017
90	7-Oil	100	7.5	0.95	0.47	0.06	0.054	0.0068	0.00024	0.000030
	8-Oil	75	7.5	0.95	0.37	0.05	0.043	0.0054	0.00019	0.000023
	9-Oil	50	7.5	0.95	0.27	0.03	0.032	0.0040	0.00014	0.000017
		Maximums	**7.5**	**0.95**	**0.47**	**0.059**	**0.054**	**0.0068**	**0.00024**	**0.000030**

[1] Total particulate matter as measured by EPA RM 201 or 201A, and 202.

[2] Based on distillate fuel oil content of 0.0015 weight percent sulfur.

[3] Based on 7.5% conversion of SO_2 to H_2SO_4.

[4] - Pb emission factor for ULSD; higher of University of Iowa and Siemens Westinghouse data - see Table B-8.

Sources: ECT, 2008.
PWPS, 2008.

Table B-7. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hourly NO_x, CO, and VOC Emission Rates (Per CT) - ULSD Fuel Oil

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[2]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[2]	CO (lb/hr)	CO (g/sec)	VOC[1] (ppmvd)[2]	VOC[1] (lb/hr)[3]	VOC[1] (g/sec)[3]
20	1-Oil	100	42	49.4	6.22	2.1	1.5	0.19	2.5	1.0	0.13
	2-Oil	75	42	38.9	4.90	3.2	1.8	0.23	4.4	1.4	0.18
	3-Oil	50	42	28.7	3.62	5.1	2.1	0.26	12.7	3.0	0.38
59	4-Oil	100	42	50.5	6.36	2.0	1.5	0.19	2.5	1.1	0.13
	5-Oil	75	42	39.8	5.01	2.3	1.4	0.18	2.5	0.8	0.10
	6-Oil	50	42	29.3	3.69	3.8	1.6	0.20	6.6	1.6	0.20
90	7-Oil	100	42	51.3	6.46	2.0	1.5	0.19	2.5	1.1	0.13
	8-Oil	75	42	40.4	5.09	2.0	1.2	0.15	2.5	0.9	0.11
	9-Oil	50	42	29.8	3.75	3.8	0.6	0.08	3.9	1.0	0.12
		Maximums	**42**	**51.3**	**6.46**	**5.1**	**2.1**	**0.26**	**12.7**	**3.0**	**0.38**

[1] 50% control for oxidation catalyst.
[2] Corrected to 15% O_2.
[3] Expressed as methane.

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

Table B-8. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hazardous Air Pollutant Hourly Emission Rates - ULSD (Per CT)

Parameter			Units	Value								
Scenario			N/A	1-O	2-O	3-O	4-O	5-O	6-O	7-O	8-O	9-O
Maximum CT Hourly Fuel Flow:			10^6 Btu/hr (HHV)	290.7	229.5	169.7	297.1	234.2	173.1	301.8	238.1	175.7

Hazardous Air Pollutant	No. 2 FO Metals Concentration[1] (ppbw)	No. 2 FO Metals Concentration[2] (ppbw)	Oil Emission Factor[3,4,5,6] (lb/10^6 Btu)	Hourly Emissions 1-O (lb/hr)	2-O (lb/hr)	3-O (lb/hr)	4-O (lb/hr)	5-O (lb/hr)	6-O (lb/hr)	7-O (lb/hr)	8-O (lb/hr)	9-O (lb/hr)
1,3-Butadiene			8.00E-06	2.33E-03	1.84E-03	1.36E-03	2.38E-03	1.87E-03	1.38E-03	2.41E-03	1.91E-03	1.41E-03
Acetaldehyde												
Acrolein												
Arsenic (As)	N/A	<DL	1.10E-05	3.20E-03	2.52E-03	1.87E-03	3.27E-03	2.58E-03	1.90E-03	3.32E-03	2.62E-03	1.93E-03
Benzene			2.75E-05	7.99E-03	6.31E-03	4.67E-03	8.17E-03	6.44E-03	4.76E-03	8.30E-03	6.55E-03	4.83E-03
Beryllium (Be)	N/A	N/A	3.10E-07	9.01E-05	7.11E-05	5.26E-05	9.21E-05	7.26E-05	5.37E-05	9.36E-05	7.38E-05	5.45E-05
Cadmium (Cd)	N/A	<DL	4.80E-06	1.40E-03	1.10E-03	8.15E-04	1.43E-03	1.12E-03	8.31E-04	1.45E-03	1.14E-03	8.43E-04
Chromium (Cr)	31.0	242.4	1.24E-05	3.60E-03	2.85E-03	2.10E-03	3.68E-03	2.90E-03	2.15E-03	3.74E-03	2.95E-03	2.18E-03
Ethylbenzene												
Formaldehyde			1.75E-05	5.09E-03	4.02E-03	2.97E-03	5.20E-03	4.10E-03	3.03E-03	5.28E-03	4.17E-03	3.08E-03
Lead (Pb)	5.3	15.0	7.67E-07	2.23E-04	1.76E-04	1.30E-04	2.28E-04	1.80E-04	1.33E-04	2.32E-04	1.83E-04	1.35E-04
Manganese (Mn)	1.9	5.5	2.81E-07	8.18E-05	6.46E-05	4.77E-05	8.36E-05	6.59E-05	4.87E-05	8.49E-05	6.70E-05	4.94E-05
Mercury (Hg)	<DL	N/A	1.20E-06	3.49E-04	2.75E-04	2.04E-04	3.56E-04	2.81E-04	2.08E-04	3.62E-04	2.86E-04	2.11E-04
Naphthalene			1.75E-05	5.09E-03	4.02E-03	2.97E-03	5.20E-03	4.10E-03	3.03E-03	5.28E-03	4.17E-03	3.08E-03
Nickel (Ni)	2.0	28.9	1.48E-06	4.30E-04	3.39E-04	2.51E-04	4.39E-04	3.46E-04	2.56E-04	4.46E-04	3.52E-04	2.60E-04
Polycyclic Aromatic Hydrocarbons			2.00E-05	5.81E-03	4.59E-03	3.39E-03	5.94E-03	4.68E-03	3.46E-03	6.04E-03	4.76E-03	3.51E-03
Propylene Oxide												
Selenium (Se)	1.9	<DL	9.72E-08	2.82E-05	2.23E-05	1.65E-05	2.89E-05	2.28E-05	1.68E-05	2.93E-05	2.31E-05	1.71E-05
Toluene												
Xylene												
Maximum Individual HAP				0.008	0.006	0.005	0.008	0.006	0.005	0.008	0.007	0.005
Total HAPs				0.036	0.028	0.021	0.036	0.029	0.021	0.037	0.029	0.022

N/A - not available <DL - less than detection limit ppbw - parts per billion, by weight

[1] - Analysis of Motor-Vehicle Fuels for Metals by Inductively Coupled Plasma-Mass Spectrometry, University of Iowa, 2000.
[2] - Survey of Ultra-Trace Metals in Gas Turbine Fuels, Siemens Westinghouse Power Corporation & Texas Oil Tech Laboratories, October 2004.
[3] - Organic pollutant emission factors reduced by 50% percent due to use of oxidation catalyst.
[4] - Organic emission factors, EPA AP-42, Stationary Gas Turbines, Table 3.1-4., April 2000.
[5] - Metallic emission factors for As, Be, Cd, and Hg; EPA AP-42, Stationary Gas Turbines, Table 3.1-5., April 2000.
[6] - Metallic emission factors for Cr, Pb, Mn, Ni, and Se; higher of University of Iowa and Siemens Westinghouse data.

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

Table B-9. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Hazardous Air Pollutant Annual Emission Rates (2 CTs)

Hazardous Air Pollutant	Annual Emissions Profile 1 (ton/yr)	Annual Emissions Profile 2 (ton/yr)
1,3-Butadiene	2.58E-04	1.43E-03
Acetaldehyde	2.40E-02	2.06E-02
Acrolein	3.84E-03	3.29E-03
Arsenic	2.35E-04	1.87E-03
Benzene	7.20E-03	1.03E-02
Beryllium	1.41E-05	5.90E-05
Cadmium	1.29E-03	1.84E-03
Chromium	1.65E-03	3.29E-03
Ethylbenzene	1.92E-02	1.65E-02
Formaldehyde	4.26E-01	3.68E-01
Lead	5.88E-04	6.20E-04
Manganese	4.47E-04	4.26E-04
Mercury	3.06E-04	4.44E-04
Naphthalene	7.80E-04	3.32E-03
Nickel	2.47E-03	2.34E-03
Polycyclic Aromatic Hydrocarbons	1.32E-03	4.16E-03
Propylene Oxide	1.74E-02	1.49E-02
Selenium	2.82E-05	3.89E-05
Toluene	7.80E-02	6.68E-02
Xylene	3.84E-02	3.29E-02
Maximum Individual HAP	0.426	0.368
Total HAPs	0.623	0.553

Sources: ECT, 2008.
PWPS, 2008.

Table B-10. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates - Annual Profile No. 1

Source	Case	No. of CTs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 4	4-Gas	2	3,500	64.0	112.0	9.4	16.5	2.7	4.7
Unit 4	4-Oil	2	0	0.0	0.0	0.0	0.0	0.0	0.0
		Totals	**3,500**	**N/A**	**112.0**	**N/A**	**16.5**	**N/A**	**4.7**

Source	Case	No. of CTs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		H_2SO_4		Lead	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 4	4-Gas	2	3,500	5.0	8.8	3.8	6.6	0.4	0.8	0.0003	0.00059
Unit 4	4-Oil	2	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0000	0.00000
		Totals	**3,500**	**N/A**	**8.8**	**N/A**	**6.6**	**N/A**	**0.8**	**N/A**	**0.0006**

Sources: ECT, 2008.
PWPS, 2008.

Table B-11. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
Annual Criteria and Sulfuric Acid Mist Pollutant Emission Rates - Annual Profile No. 2

Source	Case	No. of CTs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 4	4-Gas	2	3,000	64.0	96.0	9.4	14.1	2.7	4.1
Unit 4	4-Oil	2	500	102.6	25.7	3.0	0.8	2.1	0.5
		Totals	**3,500**	**N/A**	**121.7**	**N/A**	**14.9**	**N/A**	**4.6**

Source	Case	No. of CTs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		H_2SO_4		Lead	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Unit 4	4-Gas	2	3,000	5.0	7.5	3.8	5.7	0.4	0.7	0.00034	0.00050
Unit 4	4-Oil	2	500	15.0	3.8	0.9	0.2	0.1	0.0	0.00046	0.00012
		Totals	**3,500**	**N/A**	**11.3**	**N/A**	**5.9**	**N/A**	**0.7**	**N/A**	**0.00062**

Sources: ECT, 2008.
PWPS, 2008.

Table B-12. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Exhaust Data, Natural Gas (Per CT)

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
Component	MW (lb/mole)	100 % Load			75 % Load			50 % Load		
		20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
	Case	1-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 (ft³/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-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: ECT, 2008.
P&W, 2008.

Table B-13. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
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: ECT, 2008.
P&W, 2008.

Table B-14. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Exhaust Data, ULSD Fuel Oil (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-ULSD	4-ULSD	7-ULSD	2-ULSD	5-ULSD	8-ULSD	3-ULSD	6-ULSD	9-ULSD
Ar	39.944	0.882	0.868	0.849	0.889	0.876	0.857	0.897	0.884	0.865
N_2	28.013	74.1	73.0	71.3	74.7	73.6	72.0	75.3	74.3	72.7
O_2	31.999	14.2	13.5	12.8	14.9	14.3	13.6	15.7	15.2	14.5
CO_2	44.010	4.00	4.23	4.42	3.58	3.79	3.97	3.13	3.32	3.48
H_2O	18.015	6.85	8.41	10.63	5.86	7.37	9.57	4.88	6.31	8.45
	Totals	100.0	100.0	100.0	99.9	99.9	100.0	99.9	100.0	100.0
Exhaust MW (lb/mole)		28.65	28.49	28.27	28.68	28.54	28.34	28.73	28.63	28.40
Exhaust Flow (lb/sec)		205.0	197.0	190.0	182.0	174.0	168.0	154.0	147.0	142.0
Exhaust Temp. (°F)		793	864	921	744	814	872	699	767	823
(K)		696	735	767	669	708	740	644	681	713
Exhaust O_2 (Vol %, Dry)		15.24	14.74	14.32	15.83	15.44	15.04	16.51	16.22	15.84

B. Exhaust Flow Rates

	Flow Rates (ft³/min)								
	100 % Load			75 % Load			50 % Load		
	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F	20 °F	59 °F	90 °F
Case	1-ULSD	4-ULSD	7-ULSD	2-ULSD	5-ULSD	8-ULSD	3-ULSD	6-ULSD	9-ULSD
ACFM	392,572	400,804	406,403	334,528	340,088	345,785	271,983	275,852	280,826
Stack Dia. (ft)	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5	9.5
Velocity (fps)	92.3	94.2	95.6	78.7	80.0	81.3	64.0	64.9	66.0
Velocity (m/s)	28.1	28.7	29.1	24.0	24.4	24.8	19.5	19.8	20.1
SCFM, Dry[1]	154,094	146,395	138,864	138,106	130,559	123,950	117,859	111,214	105,804
SCFM[1] (15% O_2, Dry)	147,715	152,856	154,810	118,737	120,872	123,126	87,786	88,147	90,770

[1] At 68 °F.

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

Table B-15. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Fuel Flow Rate Data (Per CT) - ULSD Fuel Oil*

	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-ULSD	4-ULSD	7-ULSD	2-ULSD	5-ULSD	8-ULSD	3-ULSD	6-ULSD	9-ULSD
Heat Input - LHV (MMBtu/hr)	273.0	279.0	283.4	215.5	219.9	223.6	159.4	162.5	165.0
Heat Input - HHV (MMBtu/hr)	290.7	297.1	301.8	229.5	234.2	238.1	169.7	173.1	175.7
Fuel Rate (lb/hr)	14,867	15,194	15,436	11,737	11,979	12,179	8,680	8,852	8,987
Fuel Rate (10^3 gal/hr)	2.183	2.231	2.267	1.724	1.759	1.789	1.275	1.300	1.320
Fuel Rate (lb/sec)	4.130	4.220	4.288	3.260	3.328	3.383	2.411	2.459	2.496

*Includes 5.0-percent margin.

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

Table B-16. TEC Big Bend Station
Emergency Diesel Engine
Criteria Pollutant Emission Rates

Parameter	Units	Emergency Generator 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-17. TEC Bayside Power Station
Emergency Diesel Engine
Hazardous Air Pollutant Emission Rates

Parameter	Units	Emergency Generator 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-18. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
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: ECT, 2008.
P&W, 2008.

Table B-19. TEC Big Bend Station
Simple Cycle Combustion Turbines; Unit 4
CT Stack Parameters - ULSD Fuel Oil

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

Parameter	Operating Case	1-ULSD	2-ULSD	3-ULSD	4-ULSD	5-ULSD	6-ULSD	7-ULSD	8-ULSD	9-ULSD
	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	392,572	334,528	271,983	400,804	340,088	275,852	406,403	345,785	280,826
Exit Velocity	ft/sec	92.31	78.66	63.95	94.24	79.97	64.86	95.56	81.31	66.03
	m/sec	28.13	23.98	19.49	28.72	24.37	19.77	29.13	24.78	20.13
Exit Temperature	°F	793.00	744.00	699.00	864.00	814.00	767.00	921.00	872.00	823.00
	K	695.93	668.71	643.71	735.37	707.59	681.48	767.04	739.82	712.59

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

Table B-20. TEC Big Bend Station Emergency Diesel Engine Stack Parameters

Parameter	Units	Generator Diesel Engine
Height Above Grade	ft m	15.0 4.57
Exit Diameter	ft m	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

PSD APPLICABILITY ANALYSIS

APPENDIX C

TAMPA ELECTRIC COMPANY
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PSD APPLICABILITY ANALYSIS

An analysis of PSD applicability for the Big Bend Station (BBS) SCCT Project was conducted in accordance with Rule 62-212.400(2), F.A.C. The analysis includes the potential emission increases associated with the BBS SCCT Project, and the actual emission decreases associated with the permanent shutdown of existing BBS simple cycle distillate fuel oil-fired CT-1, CT-2, and CT-3.

The BBS is classified as an existing major facility. A modification to an existing major facility that results in an emission increase equal to or exceeding the significant emission rates (SERs) defined by Rule 62-210.200(279), F.A.C., is classified as a *major* modification and will be subject to the Prevention of Significant Deterioration (PSD) preconstruction permitting program for those pollutants that exceed the PSD SERs.

The procedures for determining applicability of the PSD permitting program to modifications planned at existing major facilities are specified in Rule 62-212.400(2), F.A.C. For modifications to existing emission units, the baseline actual-to-projected actual applicability test of Rule 62-212.400(2)(a)1., F.A.C. is required. A significant emissions increase of a PSD pollutant will occur if the difference, or the sum of the differences if more than one emissions unit is involved, between the projected actual emissions and the baseline actual emissions equals or exceeds the significant emissions rate for that pollutant.

For new emission units, the baseline actual-to-potential applicability test of Rule 62-212.400(2)(a)2., F.A.C. is required. A significant emissions increase of a PSD pollutant will occur if the difference, or the sum of the differences if more than one emissions unit is involved, between the potential to emit from each new emissions unit following completion of the construction and the baseline actual emissions of these units before the construction equals or exceeds the significant emissions rate for that pollutant.

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For projects that involve both existing and new emission units, the hybrid test for multiple types of emission unit per Rule 62-212.400(2)(a)3., F.A.C. is required. A significant emissions increase of a PSD pollutant will occur if the sum of the emissions increases for all emissions units, using the method specified above for each type of emissions unit equals or exceeds the significant emissions rate for that pollutant.

Baseline actual emissions is defined by Rule 62-210.200(36)(b), F.A.C. as:

> "The rate of emissions, in tons per year, of a PSD pollutant. For existing emission units (other than an electric utility steam generating unit), baseline actual emissions means the average rate, in tons per year, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding the date a complete permit application is received by the Department, except that the 10-year period shall not include any period earlier than November 15, 1990."

The existing BBS simple cycle CT-1, CT-2, and CT-3 emission units do not generate steam and therefore do not meet the Rule 62-210.200(120), F.A.C. definition of an electric utility steam generating unit. The consecutive 24-month period selected for determining baseline actual emissions for existing BBS simple cycle CT-1, CT-2, and CT-3 emission units is June 2000 through May 2002. Actual average annual emissions during this 24-month baseline period were used to determine baseline actual emissions. Baseline actual emissions for the proposed BBS SCCT Project prior to construction are zero.

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Projected actual emissions is defined by Rule 62-210.200(249), F.A.C. as:

> "The maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a PSD pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. One year is one 12-month period."

Existing BBS CT-1, CT-2, and CT-3 will permanently cease operation prior to the commencement of operation of the proposed BBS SCCT Project. Accordingly, projected actual emissions for existing BBS CT-1, CT-2, and CT-3 are zero.

Potential to Emit is defined by Rule 62-210.200(244, F.A.C., as:

> "The maximum capacity of an emission unit or facility to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the emissions unit or facility to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of an emission unit or facility."

The proposed BBS SCCT unit will be limited to no more than 3,500 hours per year (hr/yr) operation, including up to 500 hr/yr operation when firing ULSD fuel oil.

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PSD APPLICABILITY ANALYSIS

Potential emission rates for the BBS SCCT Project are summarized on Table B-1 of Appendix B.

The above procedures were used to assess PSD applicability for the BBS SCCT Project with respect to NO_x. For the remaining PSD pollutants (CO, SO_2, VOC, Pb, PM, PM_{10}, and H_2SO_4 mist), PSD applicability was conservatively analyzed by comparing BBS SCCT Project potential annual emissions to the PSD SER thresholds without consideration of any creditable emission reductions associated with the permanent shutdown of BBS CT-1, CT-2, and CT-3. Discussions of PSD applicability for NO_x and the remaining PSD pollutants are provided in the following sections.

A. NO_x

Using the hybrid test for multiple types of emission units, the creditable emission decrease resulting from the permanent shutdown of BBS CT-1, CT-2, and CT-3 was calculated by averaging the actual NO_x emission rates for these emission units over the 24-month June 2000 through May 2002 baseline period. Actual NO_x emission rates were estimated, on a monthly basis, using metered fuel oil consumption rates (gallons per month), fuel oil heat content (British thermal units [Btu] per gallon), and a NO_x emission factor of 0.88 lbs NO_x per MMBtu taken from AP-42, Section 3.1, Stationary Gas Turbines, Table 3.1-1 dated April 2000. This emission factor is applicable to uncontrolled distillate oil-fired turbines. The baseline annual average actual NO_x emission rate for BBS CT-1, CT-2, and CT-3 is 545.2 tons per year (tpy). Summaries of the baseline actual NO_x emission rates for BBS CT-1, CT-2, and CT-3 are provided on Tables C-1, C-2, and C-3. The total actual NO_x emission rate for all three CTs is included on Table C-3.

The potential to emit NO_x emission rate for the BBS SCCT Project is 122.4 tpy. Potential emission rates for the BBS SCCT Project are summarized on Table B-1 of Appendix B.

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Subtracting the creditable BBS CT-1, CT-2, and CT-3 NO_x emission reduction from the BBS SCCT Project potential NO_x emission rate results in a net decrease of 422.7 tpy. Since this change in NO_x emissions is below the PSD SER threshold of 40 tpy, the BBS SCCT Project is not subject to PSD review for NO_x. A summary of the BBS SCCT Project PSD applicability analysis for NO_x is provided on Table C-4.

B. CO, SO_2, VOC, PM, PM_{10}, Pb, and H_2SO_4 Mist

For the remaining PSD pollutants (CO, SO_2, VOC, PM, PM_{10}, Pb, and H_2SO_4 mist), PSD applicability was conservatively analyzed by comparing BBS SCCT Project potential annual emissions to the PSD significant emission rate thresholds without consideration of any creditable emission reductions associated with the permanent shutdown of BBS CT-1, CT-2, and CT-3.

BBS SCCT Project potential emission rates are provided in Appendix B, Table B-1. Since BBS SCCT Project potential emissions for CO, SO_2, VOC, PM, PM_{10}, Pb, and H_2SO_4 mist are each below the PSD SER thresholds of 100 tpy (for CO), 40 tpy (for SO_2 and VOC), 25 tpy (for PM), 15 tpy (for PM_{10}), 0.6 tpy (for Pb), and 7 tpy (for H_2SO_4 mist), the BBS SCCT Project is not subject to PSD review for these pollutants.

In summary, the BBS SCCT Project is not subject to PSD review for any pollutant. A summary of PSD applicability for all PSD pollutants is provided in Table C-5.

Table C-1. Big Bend SCCT Project
PSD Netting Analysis - CT-1 Historical Heat Input and NO_x Emission Rates

AP-42 NO_x Emission Factor: 0.88 lb NO_x / MMBtu

Year	Month	CT-1 Fuel Oil (Btu/gal)	(bbl)	(gal)	Heat Input (MMBtu)	NO_x Emissions (tons)
2000	6	138,580	1,530	64,278	8,908	3.92
2000	7	138,580	2,747	115,358	15,986	7.03
2000	8	138,580	2,837	119,157	16,513	7.27
2000	9	138,580	3,570	149,957	20,781	9.14
2000	10	138,580	484	20,320	2,816	1.24
2000	11	138,580	532	22,360	3,099	1.36
2000	12	138,580	1,830	76,878	10,654	4.69
2001	1	138,598	942	39,559	5,483	2.41
2001	2	138,598	0	0	0	0.00
2001	3	138,598	45	1,880	261	0.11
2001	4	138,598	398	16,720	2,317	1.02
2001	5	138,598	90	3,800	527	0.23
2001	6	138,598	569	23,880	3,310	1.46
2001	7	138,598	0	0	0	0.00
2001	8	138,598	737	30,959	4,291	1.89
2001	9	138,598	299	12,560	1,741	0.77
2001	10	138,598	74	3,120	432	0.19
2001	11	138,598	0	0	0	0.00
2001	12	138,598	9	360	50	0.02
2002	1	139,111	161	6,760	940	0.41
2002	2	139,111	156	6,560	913	0.40
2002	3	139,111	670	28,159	3,917	1.72
2002	4	139,111	1,975	82,958	11,540	5.08
2002	5	139,111	1,030	43,239	6,015	2.65
	Annual Average	**N/A**	**10,343**	**434,410**	**60,246**	**26.51**

Sources: ECT, 2008.
TEC, 2008.

Table C-2. Big Bend SCCT Project
PSD Netting Analysis - CT-2 Historical Heat Input and NO_x Emission Rates

AP-42 NO_x Emission Factor: 0.88 lb NO_x / MMBtu

Year	Month	CT-2				
		Fuel Oil			Heat Input	NO_x Emissions
		(Btu/gal)	(bbl)	(gal)	(MMBtu)	(tons)
2000	6	138,580	12,440	522,470	72,404	31.86
2000	7	138,580	19,168	805,066	111,566	49.09
2000	8	138,580	23,351	980,756	135,913	59.80
2000	9	138,580	21,045	883,874	122,487	53.89
2000	10	138,580	4,901	205,847	28,526	12.55
2000	11	138,580	4,662	195,812	27,136	11.94
2000	12	138,580	18,090	759,770	105,289	46.33
2001	1	138,598	13,363	561,261	77,790	34.23
2001	2	138,598	1,619	68,014	9,427	4.15
2001	3	138,598	4,286	180,003	24,948	10.98
2001	4	138,598	21,505	903,190	125,180	55.08
2001	5	138,598	6,926	290,882	40,316	17.74
2001	6	138,598	14,030	589,247	81,668	35.93
2001	7	138,598	5,220	219,252	30,388	13.37
2001	8	138,598	13,180	553,553	76,721	33.76
2001	9	138,598	6,255	262,721	36,413	16.02
2001	10	138,598	5,487	230,462	31,942	14.05
2001	11	138,598	0	0	0	0.00
2001	12	138,598	711	29,846	4,137	1.82
2002	1	139,111	3,748	157,434	21,901	9.64
2002	2	139,111	629	26,429	3,676	1.62
2002	3	139,111	9,202	386,502	53,767	23.66
2002	4	139,111	12,365	519,324	72,244	31.79
2002	5	139,111	12,502	525,102	73,047	32.14
	Annual Average	**N/A**	**117,343**	**4,928,409**	**683,443**	**300.71**

Sources: ECT, 2008.
TEC, 2008.

Table C-3. Big Bend SCCT Project
PSD Netting Analysis - CT-3 Historical Heat Input and NO_x Emission Rates

AP-42 NO_x Emission Factor: 0.88 lb NO_x / MMBtu

Year	Month	CT-3 Fuel Oil (Btu/gal)	Fuel Oil (bbl)	Fuel Oil (gal)	Heat Input (MMBtu)	NO_x Emissions (tons)
2000	6	138,580	3,404	142,956	19,811	8.72
2000	7	138,580	21,192	890,062	123,345	54.27
2000	8	138,580	25,256	1,060,770	147,002	64.68
2000	9	138,580	24,948	1,047,798	145,204	63.89
2000	10	138,580	5,017	210,707	29,200	12.85
2000	11	138,580	5,058	212,456	29,442	12.95
2000	12	138,580	17,180	721,580	99,997	44.00
2001	1	138,598	13,610	571,613	79,224	34.86
2001	2	138,598	1,852	77,784	10,781	4.74
2001	3	138,598	3,707	155,702	21,580	9.50
2001	4	138,598	21,960	922,338	127,834	56.25
2001	5	138,598	6,492	272,655	37,789	16.63
2001	6	138,598	14,531	610,312	84,588	37.22
2001	7	138,598	4,626	194,301	26,930	11.85
2001	8	138,598	1,140	47,894	6,638	2.92
2001	9	138,598	0	0	0	0.00
2001	10	138,598	0	0	0	0.00
2001	11	138,598	0	0	0	0.00
2001	12	138,598	1	32	4	0.00
2002	1	139,111	18	744	103	0.05
2002	2	139,111	75	3,150	438	0.19
2002	3	139,111	118	4,939	687	0.30
2002	4	139,111	0	4	1	0.00
2002	5	139,111	0	0	0	0.00
	Annual Average	**N/A**	**85,093**	**3,573,899**	**495,299**	**217.93**

Total for CT-1, CT-2, & CT-3		
CT-1	26.5	tons/yr
CT-2	300.7	tons/yr
CT-3	217.9	tons/yr
Total	**545.2**	**tons/yr**

Sources: ECT, 2008.
TEC, 2008.

Table C-4. Big Bend SCCT Project
PSD Netting Analysis for NO_x

Item No.	Description	Value	Units	Comments
A. CT-1, CT-2, and CT-3				
1	Baseline Period	Jun 00 - May 02	N/A	Selected consecutive 24-month period
2	Baseline Actual NO_x Emissions	545.2	ton/yr	Annual average for June 2000 - May 2002
3	Projected Actual NO_x Emissions	0.0	ton/yr	CTs will permanently cease operation prior to commencement of BBS SCCT Project
4	Change in NO_x Emissions	-545.2	ton/yr	Item 3 - Item 2
B. BBS SCCT Project				
5	Baseline Actual NO_x Emissions	0.0	ton/yr	Emissions prior to construction
6	Potential-To-Emit NO_x Emissions	122.4	ton/yr	From Appendix B, Table B-1
7	Change in NO_x Emissions	122.4	ton/yr	Item 6 - Item 5
C. Net Change in Emissions				
8	Change in NO_x Emissions	-422.7	ton/yr	Item 4 + Item 7

Sources: ECT, 2008.
TEC, 2008.

Table C-5. Big Bend SCCT Project
PSD Applicability Summary

Pollutant	Net Change in Annual Emissions[1] (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review (Y/N)
NO_x	-422.7	40	N
CO	16.5	100	N
PM	11.3	25	N
PM_{10}	11.3	15	N
SO_2	6.6	40	N
Ozone/VOC	4.7	40	N
Lead	0.00062	0.6	N
Mercury	Negligible	0.1	N
Total fluorides	Not present	3	N
H_2SO_4 mist	0.8	7	N
Total reduced sulfur (S) (including hydrogen sulfide [H_2S])	Not present	10	N
Reduced sulfur compounds (including H_2S)	Not present	10	N
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride [HCl])	Not present	40	N
Municipal waste combustor metals (measured as PM)	Not present	15	N
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not present	3.5×10^6	N
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	N

[1] Emission rates shown for CO, PM, PM_{10}, SO_2, VOC, lead, and H_2SO_4 mist represent potential annual rates for the BBS SCCT project without consideration of netting.

Sources: ECT, 2008
PWPS, 2008.
TEC, 2008.