ORIGINAL

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION MODIFICATION REQUEST

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT B COMBINED-CYCLE PROJECT

Prepared for:

OUC
The *Reliable* One®
Orlando, Florida

Prepared by:

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

ECT No. 071198-0100

February 2008

ECT
Environmental Consulting & Technology, Inc.

February 29, 2009
ECT No. 071198

RECEIVED
MAR 04 2008
BUREAU OF AIR REGULATION

Ms. Trina Vielhauer, Chief
Bureau of Air Regulation
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: Orlando Utilities Commission (OUC)
Curtis H. Stanton Energy Center—Unit B Project
Permit No. PSD-FL-373
Permit Modification Application

Dear Ms. Vielhauer:

OUC and Southern Power Company-Orlando Gasification, LLC (SPC-OG), previously submitted an air construction permit application to the Florida Department of Environmental Protection (FDEP) in February 2006 to construct a nominal 285-megawatt (MW) integrated gasification combined-cycle (IGCC) power plant (Unit B). In response to this application, FDEP issued Permit No. PSD-FL-373 in December 2006; this permit expires on July 31, 2010. In November 2007, OUC and SPC-OG mutually agreed to terminate construction of the gasifier portion of the Stanton Unit B IGCC project.

OUC plans to revise the combined-cycle portion of the IGCC project to allow firing of natural gas as the primary fuel, with ultra-low-sulfur diesel (ULSD) fuel serving as a backup fuel source. OUC will be the owner and operator of Unit B, and SPC-OG should be removed as the permittee. On behalf of OUC, enclosed are four hard copies of the Stanton Unit B Air Construction/Prevention of Significant Deterioration (PSD) permit modification application. One copy of the application is also being sent directly to the Siting Coordination Office.

If you have any questions regarding the Stanton Unit B Project, please contact Ms. Denise Stalls at 407/737-4236.

Sincerely,

ENVIRONMENTAL CONSULTING & TECHNOLOGY, INC.

Thomas W. Davis

Thomas W. Davis, P.E.
Principal Engineer

TWD/dlm

cc: Mr. Mike Halpin, Administrator
Siting Coordination Office
Florida Department of Environmental Protection
Ms. Denise Stalls, OUC
Mr. Mike Soltys, Black & Veatch
Ms. Tasha Buford, Young van Assenderp, P.A.

3701 Northwest
98th Street
Gainesville, FL
32606

(352)
332-0444

FAX (352)
332-6722

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Orlando Utilities Commission (OUC) plans to construct, own, and operate a combined-cycle combustion turbine (CCCT) power generation facility at the existing Curtis H. Stanton Energy Center (Stanton) located southeast of Orlando in Orange County, Florida. The CCCT project will support OUC's generation expansion plans and the company's obligation to provide reliable and economical electrical power to its existing and future customers.

OUC and Southern Power Company-Orlando Gasification, LLC (SPC-OG), previously submitted an air construction permit application to the Florida Department of Environmental Protection (FDEP) in February 2006 to construct a nominal 285 megawatt (MW) integrated gasification combined cycle (IGCC) power plant (Unit B). In response to this application, FDEP issued Permit No. PSD-FL-373 in December 2006; this permit expires on July 31, 2010. In November 2007, OUC and SPC-OG mutually agreed to terminate construction of the gasifier portion of the Stanton Unit B IGCC project. OUC plans to revise the combined-cycle portion of the IGCC project to allow firing of natural gas as the primary fuel, with ultra-low-sulfur diesel (ULSD) fuel serving as a backup fuel source. OUC will be the owner and operator of Unit B, and SPC-OG should be removed as the permittee.

Unit B, as modified, will be a conventional one-on-one CCCT unit comprised of a single nominal 150-MW General Electric (GE) 7FA combustion turbine generator (CTG), a fired heat recovery steam generator (HRSG), a nominal 150-MW steam turbine generator (STG), and a mechanical draft cooling tower as originally approved. The primary fuel combusted in the CTG/HRSG unit (CTG and HRSG duct burners) will be pipeline natural gas. ULSD fuel oil (CTG only) will serve as a backup fuel source. During high ambient temperature conditions, CTG steam augmentation and/or inlet air evaporative cooling may be used to increase power generation rates.

The GE 7FA CTG will be equipped with dry low-nitrogen oxides (NO_x) combustors and water injection for NO_x abatement when firing natural gas and ULSD fuel oil, respectively. The HRSG will also include selective catalytic reduction (SCR) technology for further control of NO_x emissions. Due to the change in fuels, potential emissions for the revised Unit B CCCT project will be lower than those for the previously approved IGCC project.

Operation of the proposed Unit B CCCT project will result in airborne emissions. This report, including the required permit application forms and supporting documentation included in the appendices, constitutes OUC's revision of the previously filed Unit B application.

The existing Stanton Energy Center is located in an attainment area, is one of the 28 named prevention of significant deterioration (PSD) source categories (i.e., is a fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour [MMBtu/hr] heat input), and has potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). The Unit B CCCT project will have potential emissions of NO_x, sulfur dioxide (SO_2), carbon monoxide (CO), sulfuric acid (H_2SO_4) mist, particulate matter (PM), and particulate matter less than or equal to 10 micrometers (PM_{10}) that exceed the PSD significant emission rate thresholds for *major* modifications. Consequently, the Unit B CCCT project qualifies as a major modification to an existing major facility and is subject to the PSD New Source Review (NSR) requirements of Section 62-212.400, Florida Administrative Code (F.A.C.), for NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10}. Therefore, this report and application are also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

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

- Section 3.0 describes national and state ambient air quality standards (AAQS) and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the applicable state and federal emission standards.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the vicinity of the project and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on the Chassahowitzka National Wilderness Area (NWA) Class I area.
- Section 11.0 lists the references used in preparing the report.

Appendices A and B provide emission rate calculations and the FDEP Application for Air Permit—Long Form, respectively. All dispersion modeling input and output files for the ambient impact analyses are provided in Appendix C.

1.2 SUMMARY

The Unit B CCCT project will consist of one nominal 150-MW GE 7FA CTG, an HRSG equipped with duct burners, and a nominal 150-MW STG. The GE 7FA CTG will be fired with pipeline-quality natural gas containing no more than 2.0 grains of total sulfur per one hundred standard cubic feet (gr S/100 scf) as its primary fuel. ULSD fuel oil containing no more than 0.0015 weight percent sulfur will serve as a backup fuel source for up to 1,000 hours per year (hr/yr). Ancillary project emission sources include a six-cell mechanical draft cooling tower and a 1,000,000-gallon capacity ULSD fuel oil storage tank.

Based on an evaluation of anticipated worst-case annual operating scenarios, the Unit B CCCT project will have the potential to emit 79.6 tpy of NO_x, 54.4 tpy of SO_2, 162.9 tpy of CO, 110.2 tpy of PM, 108.9 tpy of PM_{10}, and 18.6 tpy of volatile organic compounds

(VOCs). Regarding noncriteria pollutants, the Unit B CCCT project will potentially emit 8.3 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of organic and metallic compounds associated with natural gas and ULSD fuel oil combustion. Based on these annual emissions rate potentials, NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10} emissions are subject to PSD review.

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

- The use of good combustion practices and clean fuels is considered to be PM/PM_{10} BACT for the CTG/HRSG unit. The CTG/HRSG unit will use the latest burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emissions rates and will be fired primarily with low ash pipeline-quality natural gas. Use of ULSD fuel oil as a backup fuel source will be limited to no more than 1,000 hr/yr. The HRSG duct burners will be fired exclusively with pipeline-quality natural gas. Six-minute average visible emissions will not exceed 10-percent opacity.
- Use of high efficiency drift eliminators represents PM/PM_{10} BACT for the mechanical draft cooling tower. The cooling tower will have a drift rate of 0.0005 percent of the recirculating water flow rate. This cooling tower drift rate is consistent with recent FDEP BACT determinations for similar cooling towers.
- The use of clean fuels is considered to be BACT for SO_2 and H_2SO_4 mist. Pipeline-quality natural gas combusted in the CTG and HRSG duct burners will contain no more than 2.0 gr S/100 scf. ULSD fuel oil combusted in the CTG will contain no more than 0.0015 weight percent sulfur.
- The GE 7FA CTG will be equipped with dry low-NO_x combustors and water injection for NO_x abatement when firing natural gas and ULSD fuel oil, respectively. The HRSG will also include SCR technology for further control of NO_x emissions. For all normal operating loads, CTG/HRSG unit NO_x exhaust concentrations will not exceed 2.0 and 8.0 parts per million by dry volume (ppmvd), corrected to 15-percent oxygen, on a 24-hour block average basis for natural gas and ULSD fuel oil, respectively. These concentra-

tion are consistent with recent FDEP BACT determinations for similar CCCT projects (e.g., the Florida Municipal Power Agency [FMPA] Treasure Coast Energy Center).

- Good combustion practices will be used to reduce emissions of CO. For all normal operating loads, CTG/HRSG unit CO exhaust concentrations will not exceed 8.0 ppmvd, corrected to 15-percent oxygen, on a 24-hour block average basis and 6.0 ppmvd, corrected to 15-percent oxygen, on a 12-month rolling average basis for both natural gas and ULSD fuel oil. These concentrations are consistent with recent FDEP BACT determinations for similar CCCT projects (e.g., the FMPA Treasure Coast Energy Center).
- The Unit B CCCT project is projected to emit NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10} in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the CCCT project qualifies for the Rule 62-212.400(3)(e), F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(279), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was not required.
- The ambient impact analysis demonstrates that project impacts for the pollutants emitted in significant amounts will be below the U.S. Environmental Protection Agency (EPA)-defined PSD Class I significant impact levels. Accordingly, a multisource interactive assessment of PSD Class I increment consumption was not required.
- Based on refined dispersion modeling, the Unit B CCCT project will not cause nor contribute to a violation of any NAAQS, Florida AAQS or PSD increment for Class I or Class II areas.

- The ambient impact analysis also demonstrates that Unit B CCCT project impacts will be well below levels detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Chassahowitzka NWA) is located approximately 145 kilometers (km) northwest of the project site. The ambient impact analysis demonstrates that the Unit B CCCT project will have no adverse visibility and deposition impacts on this Class I area.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT LOCATION, AREA MAP, AND PLOT PLAN

The Unit B CCCT project will be constructed on a portion of the approximately 3,280-acre site of OUC's existing Stanton Energy Center located southeast of Orlando in Orange County, Florida. Figure 2-1 shows the general location of the Stanton Energy Center within the state of Florida. Figure 2-2 shows the Stanton site relative to Orlando, including nearby major roadways.

Approximately 1,100 acres of the 3,280-acre site have been licensed by the state of Florida for an ultimate site capacity of up to 2,000 MW of power generation and supporting facilities. The Unit B CCCT project will be constructed within this licensed 1,100 acres. Most of the remaining 2,180 acres of the Stanton Energy Center site has been left in its preexisting condition and provides buffer between the main generating units and the surrounding area. Figure 2-3 provides a recent aerial photograph of the plant site and immediate surroundings.

The major equipment associated with the Unit B CCCT project will be located south of Stanton Unit A and north of the existing Stanton Energy Center coal-fired units. Figure 2-4 shows the major process equipment and structures associated with the Unit B CCCT project.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The Unit B combined-cycle island power block will consist of a GE 7FA CTG with a dedicated HRSG, a single STG (i.e., a 1-on-1 CT/HRSG configuration), and associated auxiliary and control systems. The CTG/HRSG unit will be constructed to allow only combined-cycle operation (i.e., the CTG will not have a bypass stack allowing simple-cycle operation). The HRSG will be equipped with natural gas-fired duct burners to boost power generation capability during periods of peak demand. During high ambient temperature conditions, CTG steam augmentation and/or inlet air evaporative cooling may also be used to increase power generation rates. Figure 2-5 provides a simple schematic of a basic combined-cycle system showing a CTG, an HRSG, and other key components.

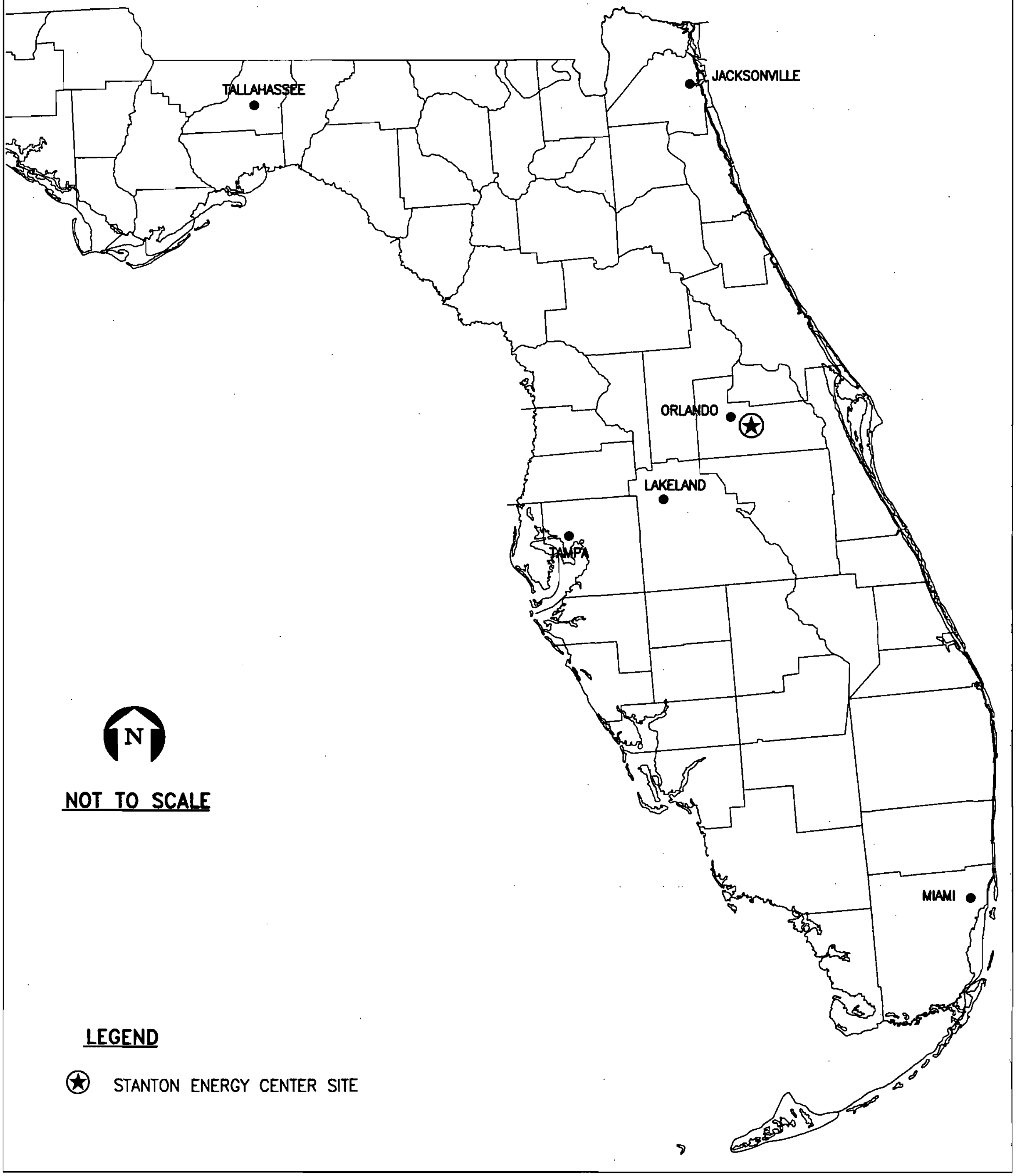

FIGURE 2-1.
LOCATION OF THE STANTON SITE WITHIN THE STATE OF FLORIDA
Source: ECT, 2008.

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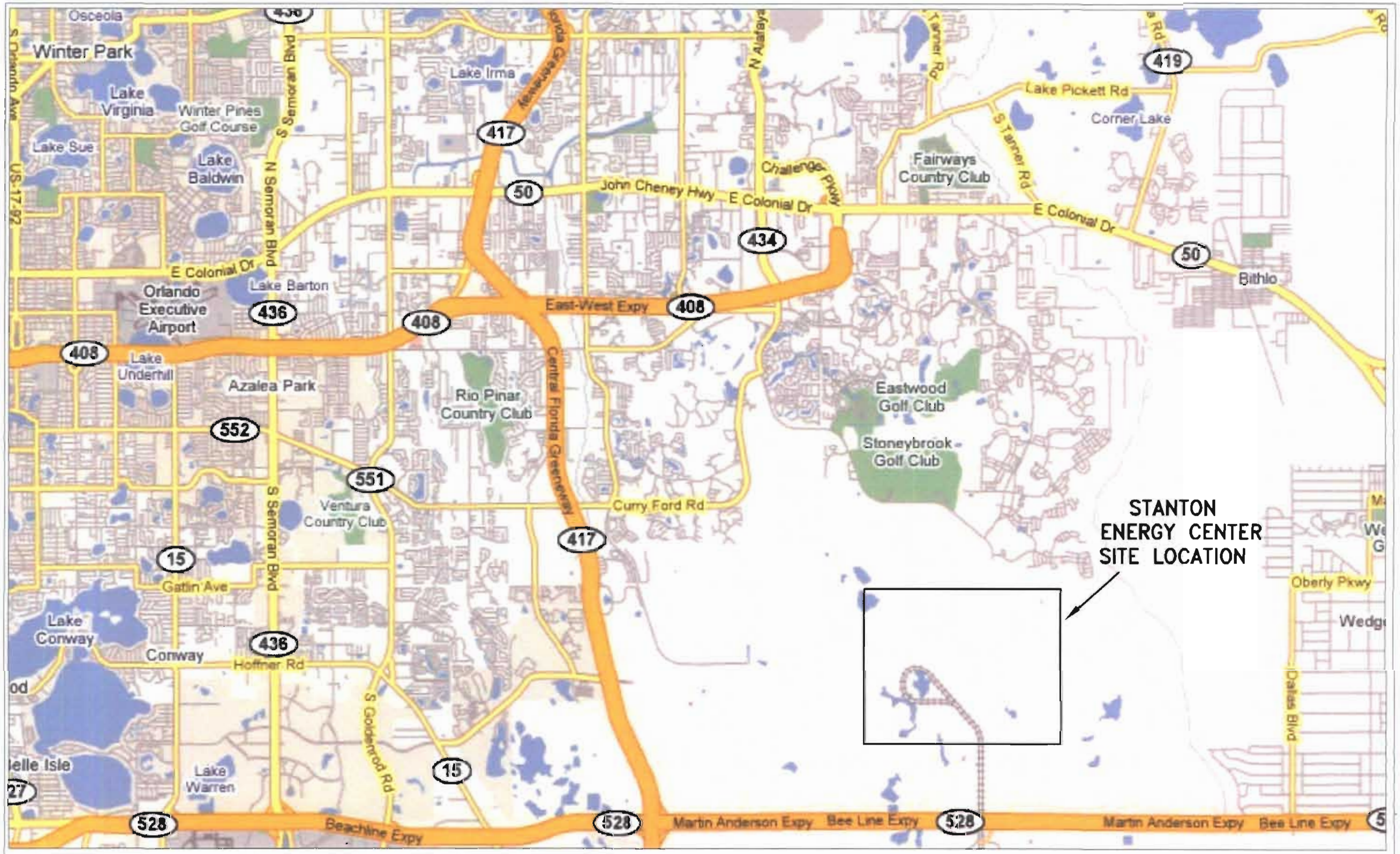

FIGURE 2-2.
STANTON SITE LOCATION RELATIVE TO ORLANDO

Source: Google maps, 2008; ECT, 2008.

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FIGURE 2-3.
2007 AERIAL OF STANTON SITE AND SURROUNDING AREA

Sources: SJRWMD Aerials, 2007; ECT, 2008.

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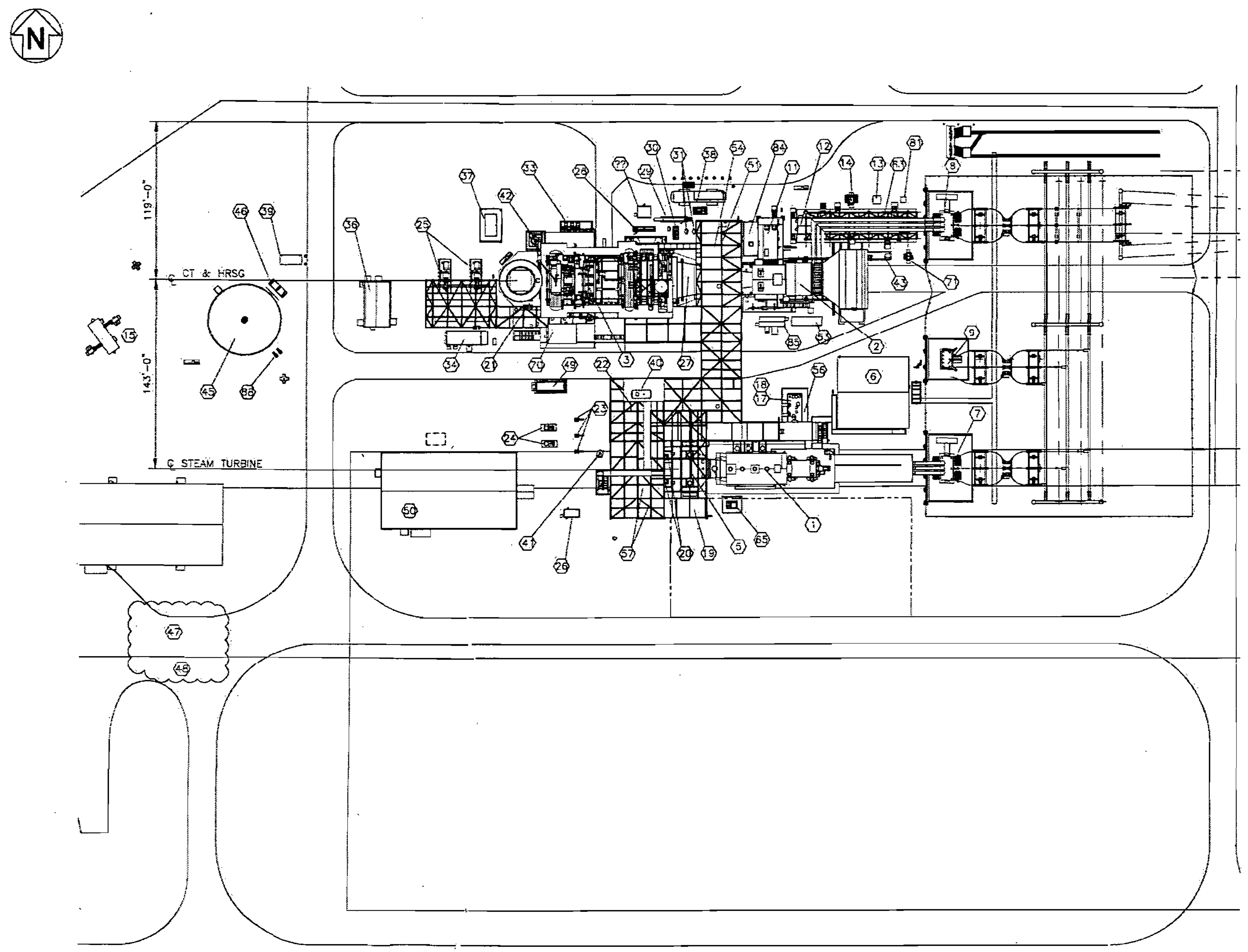

LEGEND

①	STEAM TURBINE
②	COMBUSTION TURBINE
③	HEAT RECOVERY STEAM GENERATOR
④	COOLING TOWER (SEE DWG. DBM2500 SHT. 2)
⑤	CONDENSER
⑥	ELECTRICAL BUILDING
⑦	STEAM GENERATOR GSU
⑧	COMBUSTION TURBINE GSU
⑨	STATION SERVICE TRANSFORMER
⑩	SPARE
⑪	COMBUSTION TURBINE ACCESSORY MOD.
⑫	COMBUSTION TURBINE PEEC
⑬	DC LINK TRANSFORMER
⑭	ISOLATION TRANSFORMER
⑮	480V TRANSFORMER & MCC
⑯	NITROGEN TANK
⑰	STEAM TURBINE LUBE OIL SKID
⑱	STEAM TURBINE HPU
⑲	GLAND STEAM CONDENSER
⑳	CONDENSATE PUMPS
㉑	CONDENSATE RECIRC PUMPS
㉒	AIR COMPRESSOR
㉓	SERVICE WATER HEAT EXCHANGERS
㉔	SERVICE WATER PUMPS
㉕	CC BOILER FEED PUMPS
㉖	FIRE PROTECTION VALVE HOUSE
㉗	SCANNER AIR BLOWER
㉘	FUEL GAS PIPING MODULES
㉙	FUEL GAS HEATER
㉚	FUEL GAS ELECTRIC WATER HEATER
㉛	FUEL GAS FILTER
㉜	GAS METERING STATION (SEE DWG. DBM2500 SHT. 2)
㉝	SCR AMMONIA BLR/CONTROL
㉞	CEMS BUILDING
㉟	SPARE
㊱	WATER ANALYSIS BUILDING
㊲	PHOSPHATE FEED PUMP SKID
㊳	ANHYDROUS AMMONIA SUPPLY SYSTEM
㊴	CO2 SKID
㊵	CLOSED LOOP COOLING WTR TANK
㊶	STEAM TURBINE BLOWDOWN TANK
㊷	HRSG BLOWDOWN TANK
㊸	CT CO2 TANK
㊹	CHEMICAL FEED TANKS (SEE DWG. DBM2500 SHT. 2)
㊺	DEMIN STORAGE TANK 53'-0"ø×40'-0"HIGH 650,000 GALS.
㊻	CONDENSATE MAKEUP PUMPS
㊼	WASTE WATER SUMP
㊽	OIL/WATER SEPARATOR
㊾	MAIN STEAM SUMP
㊿	CONTROL/ADMIN BLDG
(51)	SUMP "A"
(52)	SPARE
(53)	WASH WATER SKID
(54)	SUMP "A" PUMPS
(55)	SPARE
(56)	TURBINE SEAL OIL SKID
(57)	VACUUM PUMPS
(58)	WAREHOUSE (SEE DWG. DBM2500 SHT. 2)
(59)	FIRE PROT. PUMP HSE (LATER)
(60)	FIRE PROT. STORAGE TK (LATER)
(61)	SPARE
(62)	GAS CONDITIONING STATION (SEE DWG. DBM2500 SHT. 2)
(63)	LCI EXCITATION COMPT (LEC)
(64)	SPARE
(65)	AQUEOUS AMMONIA TANK
(66)	SPARE
(68)	SPARE
(70)	DCS BUILDING
(71)	EXCITATION TRANSFORMER
(73)	SPOILS AREA
(81)	AC LINK REACTOR
(84)	LIQUID FUEL ATOMIZER
(85)	WATER INJECTION SKID
(86)	FUEL OIL STORAGE TANK
(87)	FUEL OIL TRANSFER PUMPS
(88)	WATER INJECTION BOOSTER PUMPS

NOTES:

1. SITE COORDINATES ARE AT FLORIDA STATE PLANE EAST ZONE NAD 1983.
2. FOR EQUIPMENT LEGEND SEE DWG. DBM2500 SHT. 3
3. SITE RIDGELINE ELEVATION = 81'-0" ±

FIGURE 2-4.

DETAILED ARRANGEMENT

Source: SCS, 2008.

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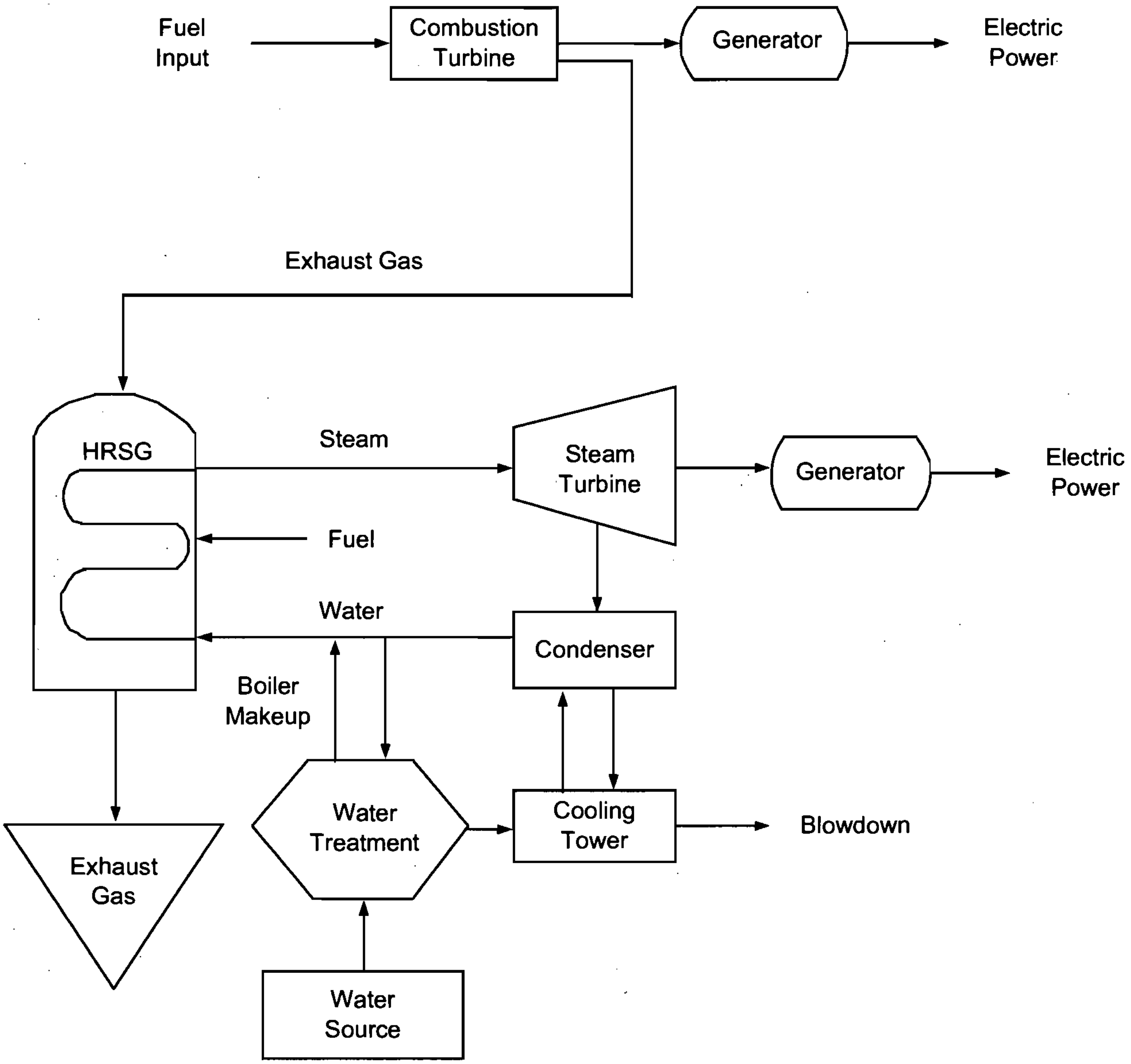

FIGURE 2-5.

SIMPLIFIED FLOW DIAGRAM OF A BASIC COMBINED-CYCLE POWER SYSTEM

Source: ECT, 2005.

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The Unit B CTG/HRSG will be capable of continuous operation for up to 8,760 hr/yr firing natural gas. Backup ULSD fuel oil may be fired for up to 1,000 hr/yr. Nominal generation capacity for the Unit B CTG/HRSG will be 300-MW at base load.

Combustion of natural gas (CTG and HRSG duct burners) and ULSD fuel oil (CTG only) will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, H_2SO_4 mist, and trace amounts of metallic and organic compounds including hazardous air pollutants (HAPs). The CTG/HRSG emissions will be the primary source of pollutants from the Unit B CCCT project. Appendix A provides detailed emission estimates for the Unit B CCCT project.

Emission control systems proposed for the CTG/HRSG unit include the use of dry low-NO_x (when firing natural gas), water injection (when firing ULSD fuel oil), and SCR for control of NO_x; good combustion practices for abatement of CO and VOCs; and use of low-sulfur, low-ash fuels to minimize PM/PM_{10}, SO_2, H_2SO_4 mist, and HAP emissions. Discussions of the specific emission control systems proposed for each Unit B CCCT project emission source are provided in Section 5.0, Best Available Control Technology.

Combustion Turbine

The Unit B CCCT project will use a GE 7FA gas turbine generator (or CTG). The Unit B F-Class CTG will be capable of producing a nominal 150 MW of electricity and will normally operate between 50- and 100-percent load while firing either natural gas or ULSD fuel oil. The GE 7FA CTG will be equipped with dry low-NO_x combustors and water injection for NO_x abatement when firing natural gas and ULSD fuel oil, respectively.

CTGs are advanced technology engines that convert latent fuel energy into mechanical energy using compressed hot gas (i.e., air and products of combustion) as the working medium. CTGs deliver mechanical energy 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. In the CTG cycle, ambient air is first filtered and then compressed by the CTG compressor section. The CTG compressor section increases the pressure of the combustion air stream and also raises its temperature. The compressed combustion air is then combined with fuel, which is ignited in the CTG's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases expand and drive the CTG's turbine section to produce rotary shaft power. The turbine rotor is coupled to an electric generator as well as to the CTG combustion air compressor rotor. During high ambient temperature conditions, CTG steam augmentation and/or inlet air evaporative cooling may be used to increase power generation rates.

Heat Recovery Steam Generator

When CTGs are used as simple-cycle (stand-alone) units, the hot combustion gases are released to the atmosphere at approximately 1,000 degrees Fahrenheit (°F) after they have passed through the turbine. The efficiency of a power plant's electric power production is significantly improved when the simple-cycle design is modified to include an HRSG and STG in what is termed a combined-cycle power plant. In a combined-cycle system, the heat in the CTG exhaust gases is used to generate steam in an HRSG, where gas temperatures are reduced to approximately 270°F before release to the atmosphere. The steam is then used to drive a steam turbine and generator to produce additional electricity as previously shown in Figure 2-5.

The Unit B CTG will exhaust into a conventionally designed, triple-pressure level HRSG. High-, medium-, and low-pressure superheated steam are generated in the HRSG and sent to the STG. Steam exhausted from the high-pressure turbine is reheated in the HRSG, expanded through the intermediate- and low-pressure turbines, and then condensed. The HRSG unit will furnish steam to one STG for an additional nominal 150-MW generation of electricity. The HRSG unit will be equipped with natural gas-fired duct burners to increase power generation rates during periods of peak demand.

Cooling Tower

The Unit B CCCT power block will be equipped with a six-cell wet evaporative mechanical draft cooling tower for the purpose of providing the cooling necessary to condense the steam that exhausts from the STG. A water-cooled steam surface condenser will also be used, and the condensate will be collected in the hot well of the condenser and pumped back to the HRSG. Cooling water will be supplied to the surface condenser from the six-cell cooling tower.

2.3 EMISSION AND STACK PARAMETERS

The primary source of Unit B CCCT project emissions results from the combustion of natural gas and ULSD fuel oil in the CT/HRSG unit. Emissions from the CTG/HRSG unit stack are primarily NO_x, SO_2, CO, VOC, PM, H_2SO_4 mist, and other trace constituents

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant CT/HRSG emission rates for natural gas and ULSD fuel oil firing. Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are generally projected to occur for CTG/HRSG operations at low ambient temperature (i.e., 20°F), baseload, and ULSD fuel oil firing. Appendix A provides the bases for these emission rates.

Tables 2-3 and 2-4 provide maximum Unit B HAP hourly emission rates for natural gas and ULSD fuel oil firing, respectively. HAP emissions consist primarily of trace amounts of organic and metallic compounds associated with the combustion of natural gas and ULSD fuel oil.

Table 2-5 presents projected maximum annualized criteria and HAP emissions for the Stanton Unit B CCCT project.

Tables 2-6 and 2-7 provide stack parameters for the CTG/HRSG unit for natural gas and ULSD fuel oil firing, respectively. Table 2-8 summarizes the stack parameters for the Unit B CCCT project cooling tower.

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures—Natural Gas

CCCT 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	19.9	2.51	10.7	1.35	13.9	1.75	17.3	2.18	2.9	0.37	Neg.	Neg.
	70†	19.8	2.49	9.8	1.24	12.7	1.61	15.9	2.00	2.7	0.34	Neg.	Neg.
	95‡	24.6	3.10	12.4	1.57	16.1	2.09	37.2	4.69	4.2	0.53	Neg.	Neg.
75	20	19.6	2.46	8.7	1.09	11.1	1.40	13.9	1.75	2.3	0.29	Neg.	Neg.
	70	19.4	2.45	8.0	1.01	10.2	1.29	12.8	1.81	2.1	0.27	Neg.	Neg.
	95	19.4	2.44	7.5	0.95	9.6	1.21	12.0	1.52	2.0	0.25	Neg.	Neg.
50	20	19.2	2.42	6.9	0.87	8.8	1.11	11.0	1.38	1.8	0.23	Neg.	Neg.
	70	19.1	2.41	6.4	0.80	8.1	1.02	10.1	1.27	1.7	0.21	Neg.	Neg.
	95	19.1	2.40	6.0	0.75	7.6	0.96	9.5	1.20	1.6	0.20	Neg.	Neg.

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

*Filterable PM_{10}.
†Evaporative cooling.
‡Evaporative cooling, steam augmentation, and duct burner firing.

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

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures—ULSD Fuel Oil

CCCT Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	34.6	4.36	3.2	0.41	65.4	8.24	39.8	5.01	8.0	1.01	Neg.	Neg.
	70†	34.5	4.35	3.0	0.38	60.3	7.59	36.7	4.62	7.5	0.94	Neg.	Neg.
	95†	34.5	4.35	2.9	0.36	58.1	7.32	35.4	4.46	7.0	0.88	Neg.	Neg.
75	20	34.5	4.34	2.6	0.33	52.0	6.56	31.7	3.99	6.0	0.76	Neg.	Neg.
	70	34.4	4.34	2.4	0.30	48.1	6.06	29.3	3.69	6.0	0.76	Neg.	Neg.
	95	34.4	4.34	2.3	0.29	45.5	5.74	27.7	3.49	5.5	0.69	Neg.	Neg.
50	20	34.4	4.33	2.0	0.26	40.5	5.10	24.7	3.11	5.0	0.63	Neg.	Neg.
	70	34.3	4.33	1.9	0.24	37.5	4.73	22.8	2.88	5.0	0.63	Neg.	Neg.
	95	34.3	4.32	1.8	0.23	35.4	4.46	21.5	2.71	4.5	0.57	Neg.	Neg.

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

*Filterable PM_{10}.
†Evaporative cooling.

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

Table 2-3. Maximum HAP Emissions Rates for 100-Percent Load and 20°F Ambient Temperature—Natural Gas

lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
1,3-Butadiene		Acetaldehyde		Acrolein		Arsenic		Benzene		Beryllium	
8.26E-04	1.04E-04	7.69E-02	9.69E-03	123E-02	1.55E-03	3.77E-04	4.75E-05	2.31E-02	2.91E-03	2.26E-05	2.85E-06
Cadmium		Chromium		Ethylbenzene		Formaldehyde		Lead		Manganese	
2.07E-03	2.61E-04	2.64E-03	3.32E-04	6.15E-02	7.75E-03	5.84E-01	7.36E-02	9.42E-04	1.19E-04	7.16E-04	9.02E-05
Mercury		Naphthalene		Nickel		PAH		Propylene Oxide		Selenium	
4.90E-04	6.17E-05	2.50E-03	3.15E-04	3.96E-03	4.99E-04	4.23E-03	5.33E-04	5.57E-02	7.02E-03	4.52E-05	5.70E-06
Toluene		Xylene									
2.50E-01	3.15E-02	1.23E-01	1.55E-02								

Note: g/s = gram per second.
lb/hr = pound per hour.
PAH = polycyclic aromatic hydrocarbon.

Source: ECT, 2008.

Table 2-4. Maximum HAP Emissions Rates for 100-Percent Load and 20°F Ambient Temperature—ULSD Fuel Oil

lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
1,3-Butadiene		Acetaldehyde		Acrolein		Arsenic		Benzene		Beryllium	
3.36E-02	4.23E-03	N/A		N/A		2.31E-02	2.91E-03	1.15E-01	1.45E-02	6.50E-04	8.19E-05
Cadmium		Chromium		Ethylbenzene		Formaldehyde		Lead		Manganese	
1.01E-02	1.27E-03	2.62E-02	3.30E-03	N/A		7.34E-02	9.25E-03	1.62E-03	2.04E-04	5.95E-04	7.49E-05
Mercury		Naphthalene		Nickel		PAH		Propylene Oxide		Selenium	
2.52E-03	3.17E-04	7.34E-02	9.25E-03	3.12E-03	3.94E-04	8.39E-02	1.06E-02	N/A		2.05E-04	2.59E-05
Toluene		Xylene									
N/A		N/A									

Note: g/s = gram per second.
lb/hr = pound per hour.
NA = not applicable.
PAH = polycyclic aromatic hydrocarbon.

Source: ECT, 2008.

Table 2-5. Unit B CCCT Project Annual Criteria and HAP Pollutant Emission Rates

Pollutant	Unit B CCCT (tpy)†
NO_x	79.6
CO	162.9
PM*	110.2
PM_{10}*	108.9
SO_2	54.4
VOC	18.6
H_2SO_4 mist	8.3
1,3-Butadiene	0.018
Acetaldehyde	0.309
Acrolein	0.049
Arsenic	0.012
Benzene	0.135
Beryllium	0.00038
Cadmium	0.012
Chromium	0.021
Ethylbenzene	0.247
Formaldehyde	2.4
Lead	0.004
Manganese	0.003
Mercury	0.003
Naphthalene	0.043
Nickel	0.016
Polynuclear aromatic hydrocarbons	0.054
Propylene oxide	0.224
Selenium	0.00026
Toluene	1.00
Xylene	0.494
Total HAPs	4.9

†Maximum for Annual Profiles 1, 2, and 3.
*Filterable and condensable particulate matter.

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

Table 2-6. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	205.1	62.5	227	382	60.0	18.3	20.0	6.10
	70*	205.1	62.5	224	380	54.9	16.7	20.0	6.10
	95†	205.1	62.5	212	373	55.5	16.9	20.0	6.10
75	20	205.1	62.5	214	374	46.3	14.1	20.0	6.10
	70	205.1	62.5	212	373	43.5	13.3	20.0	6.10
	95	205.1	62.5	212	373	41.6	12.7	20.0	6.10
50	20	205.1	62.5	203	368	37.2	11.4	20.0	6.10
	70	205.1	62.5	203	368	35.6	10.9	20.0	6.10
	95	205.1	62.5	203	368	34.6	10.5	20.0	6.10

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

*Evaporative cooling.
†Evaporative cooling, steam augmentation, and duct burner firing.

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

Table 2-7. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—ULSD Fuel Oil

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	205.1	62.5	262	401	66.1	20.1	20.0	6.10
	70*	205.1	62.5	257	398	60.1	18.3	20.0	6.10
	95*	205.1	62.5	253	396	57.8	17.6	20.0	6.10
75	20	205.1	62.5	248	393	49.8	15.2	20.0	6.10
	70	205.1	62.5	244	391	46.9	14.3	20.0	6.10
	95	205.1	62.5	241	389	44.9	13.7	20.0	6.10
50	20	205.1	62.5	235	386	39.6	12.1	20.0	6.10
	70	205.1	62.5	234	386	38.1	11.6	20.0	6.10
	95	205.1	62.5	232	384	37.0	11.3	20.0	6.10

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

*Evaporative cooling.

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

Table 2-8. Stack Parameters for Unit B CCCT Project Cooling Tower (Per Cell)

Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
ft	meters	°F	K	ft/sec	m/sec	ft	meters
50.0	15.2	90	305	23.1	7.1	33.5	10.21

Note: ft = foot.
°F = degree Fahrenheit.
K = Kelvin.
ft/sec = foot per second.
m/sec = meter per second.

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

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

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

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The Stanton Energy Center is located in eastern Orange County approximately 13 miles southeast of the city of Orlando. Orange County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs], SO_2, and nitrogen dioxide [NO_2]), unclassifiable/attainment (for CO, 1- and 8-hour ozone, and particulate matter less than or equal to 2.5 micrometers [$PM_{2.5}$]), and not designated (for lead). Orange County is designated attainment (for ozone, SO_2, CO, and NO_2) and unclassifiable (for PM_{10} and lead) by Section 62-204.340, F.A.C. Orange County is also designated an air quality maintenance area (AQMA) for ozone pursuant to Rule 62-204.340(4)(a)1., F.A.C.

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

3.2 NONATTAINMENT NSR APPLICABILITY

The Stanton Energy Center is located in Orange County. As noted previously, Orange County is presently designated as either better than national standards or

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

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
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]	0.08	0.08	
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 μg/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 μg/m^3.

[5] 98th percentile concentration, as determined in accordance with 40 CFR 50 Appendix N.

[6] Arithmetic mean concentration, as determined in accordance with 40 CFR 50 Appendix N.

[7] Standard attained when the expected number of calendar days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.

[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.

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

unclassifiable/attainment for all criteria pollutants. Accordingly, the Unit B CCCT project is not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The Unit B CCCT project will have potential emissions greater than one or more of the PSD significant emission rates listed in Rule 62-210.200(278), F.A.C. Accordingly, the Unit B CCCT project qualifies as a major modification to an existing major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants that are emitted at or above the specified PSD significant emission rate levels. Table 3-2 provides comparisons of estimated potential annual emission rates for the Unit B CCCT project and the PSD significant emission rate thresholds. As shown in this table, potential emissions of NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10} are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Appendix A provides detailed emission rate estimates for the Unit B CCCT project.

3.4 PSD REQUIREMENTS

3.4.1 CONTROL TECHNOLOGY REVIEW

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

> "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account: (1) energy, environmental, and economic impacts, and other costs, (2) all scientific, engineering, and technical material and other information available to the Department, and (3) the emission limiting standards or BACT determinations of Florida and any other state, determines is achievable through application of production processes and available methods, systems and techniques techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant that exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units, which emit or increase emissions of the

Table 3-2. Projected Unit B CCCT Project Emissions Compared to PSD Significant Emission Rates

Pollutant	CCCT Project Maximum Annual Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	79.6	40	Yes
CO	162.9	100	Yes
PM	110.2	25	Yes
PM_{10}	108.9	15	Yes
SO_2	54.4	40	Yes
Ozone/VOC	18.6	40	No
Lead	0.004	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Not present	3	No
H_2SO_4 mist	8.3	7	Yes
Total reduced sulfur (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 μg/m^3, 24-hour average	N/A	Any amount	No

Sources: Rule 62-210.200(278), F.A.C.
OUC, 2008.
ECT, 2008.

applicable pollutants, involved in a major modification or a new major source must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

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

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

1. All available control technology alternatives are identified based on knowledge of the particular industry of the applicant, control technology vendors, technical journals and reports, and previous control technology permitting decisions for other identical or similar sources.
2. The identified available control technologies are evaluated for technical feasibility. If a control technology has been installed and operated successfully on the type of source under review, it is considered demonstrated and technically feasible. An undemonstrated control technology may be considered technically feasible if it is available and applicable. A control technology is considered available if it can be obtained commercially (i.e., the technology has reached the licensing and commercial sales phase of development). An available control technology is applicable if it can reasonably be installed and operated on the source type under consideration. Undemonstrated available control technologies that are determined to be technically infeasible, based on physical, chemical, and engineering principals, are eliminated from further consideration.
3. The technically feasible technology alternatives are rank-ordered by stringency into a control technology hierarchy.
4. The hierarchy is evaluated starting with the *top*, or most stringent alternative to determine economic, environmental, and energy impacts and to assess the

feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is accepted as BACT from an economic and energy standpoint, evaluation of energy and economic impacts is not required since the only reason for conducting these assessments is to document the rationale for rejecting an alternative technology as BACT. Instead, the applicant proceeds to evaluate the top case control technology for impacts of unregulated air pollutants or impacts in other media (i.e., collateral environmental impacts). If there are no issues regarding collateral environmental impacts, the BACT analysis is complete, and the top case control technology alternative is proposed as BACT. If the top control alternative is not applicable due to adverse energy, environmental, or economic impacts, it is rejected as BACT and the next most stringent control alternative is then considered.

5. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the evaluated pollutant.

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

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

3.4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(7), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those which the source would potentially emit in significant amounts (i.e., those that exceed the PSD significant emission rate thresholds previously shown in Table 3-2).

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

Rule 62-212.400(3)(e), F.A.C., provides an exemption that excludes or limits the pollutants for which an air quality monitoring analysis is conducted. This exemption states that a proposed facility will be exempt from the monitoring requirements of Rule 62-212.400(7), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the new source would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400(3)(e)1., F.A.C. (see Table 3-3). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the Unit B CCCT project is discussed in Section 8.2.

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

Averaging Time	Pollutant	*De Minimis* Level ($\mu g/m^3$)
Annual	NO_2	14
Quarterly	Lead	0.1
24-Hour	PM_{10}	10
	SO_2	13
	Mercury	0.25
	Fluorides	0.25
8-Hour	CO	575
1-Hour	Total reduced sulfur	10
	H_2S	0.2
	Reduced sulfur compounds	10
NA	Ozone	100 tpy of VOC or NO_x emissions

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

3.4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). The FDEP rules specifically require the use of applicable EPA atmospheric dispersion models in determining estimates of ambient concentrations (refer to Rule 62-204.220[4], F.A.C.). Guidance for the use and application of dispersion models is presented in the EPA *Guideline on Air Quality Models* (GAQM) as published in Appendix W to 40 CFR 51. Criteria pollutants may be exempt from the full source impact analysis if the net increase in impacts due to the new source or modification is below the appropriate Rule 62-210.200(279), F.A.C., significant impact level (SIL), as presented in Table 3-4. EPA has proposed SILs for Class I area; these levels are provided in Table 3-5.

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

Various lengths of record for meteorological data can be used for impact analyses. A 5-year period can be used with corresponding evaluation of the highest of the second-highest (HSH) short-term concentrations for comparison to AAQS or PSD increments. The term *highest, second-highest* refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term PSD increments specify the standard should not be exceeded at any location more than once per year. If less than 5 years of meteorological data are used, the highest concentration at each receptor must be used.

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA

Table 3-4. FDEP SILs

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

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

Table 3-5. EPA SILs—Class I Areas

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

Source: EPA Proposed, 1996; 61FR 38249.

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

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

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which include revised NAAQS for PM_{10} and $PM_{2.5}$, became effective on October 17, 2006. Due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for state permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 3-6.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline*

Table 3-6. PSD Allowable Increments

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

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

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

concentration means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

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

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

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

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

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

3.4.4 ADDITIONAL IMPACT ANALYSES

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

The growth analysis generally includes:

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

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

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

3.5 HAP 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 amendments to the CAA) reflect maximum achievable control technology (MACT). Section 4.2 provides a discussion of the NESHAPs program and its applicability to the Unit B CCCT 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 40 CFR 60.

The Unit B CCCT project will include a GE 7FA CTG. This CTG will be subject to the applicable requirements of NSPS Subpart KKKK as discussed in the following subsection.

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

The Unit B CTG/HRSG will be fired primarily with natural gas. ULSD fuel oil may be fired as a backup fuel source for up to 1,000 hr/yr. NSPS Subpart KKKK specifies emission limitations, monitoring, reporting, and recordkeeping requirements for NO_x and SO_2. Applicable NSPS Subpart KKKK emission standards for the Unit B CTG/HRSG are summarized as follows:

- $\underline{NO_x}$—15 ppmvd at 15-percent oxygen or 0.43 pound per megawatt-hour (lb/MWh) gross energy output (when firing natural gas); and 42 ppmvd at 15-percent oxygen or 1.3 lb/MWh gross energy output (when firing fuels other than natural gas [e.g., ULSD fuel oil]).
- $\underline{SO_2}$—0.90 lb/MWh gross energy output or 0.060 pound per million British thermal units (lb/MMBtu).

The NSPS Subpart KKKK standards also include emissions associated with HRSG duct burners. HRSG duct burners regulated under NSPS Subpart KKKK are exempt from the requirements of NSPS Subparts Da, Db, and Dc. The Unit B CTG/HRSG will comply with the applicable requirements of NSPS Subpart KKKK.

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 of the CAA. Section 112 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 (CTs) (40 CFR 63, Subpart YYYY) on March 5, 2004. These regulations apply to stationary CTs located at major sources of HAPs. On April 7, 2004, EPA proposed to delist four subcategories of CTs from the CAA Section 112(c) categorical list. On August 18, 2004, EPA stayed the effectiveness of two subcategories of turbines subject to Subpart YYYY: lean pre-mix gas-fired turbines and diffusion flame gas-fired turbines. Accordingly, only oil-fired stationary CTs are currently subject to emission limits under Subpart YYYY. Owners or operators of oil-fired stationary CTs subject to Subpart YYYY are required to submit initial notifications, conduct initial performance testing, submit periodic compliance reports, and maintain records to demonstrate continuous compliance. New gas-fired stationary CTs are only required to submit an initial notification. In the event the CT source categories are not delisted, the stay will be lifted and new lean pre-mix and diffusion flame gas-fired CTs will be required to meet the requirements of Subpart YYYY.

Subpart YYYY defines a *diffusion flame oil-fired stationary combustion turbine* as:

> "(1)(i) Each stationary combustion turbine which is equipped only to fire oil using diffusion flame technology, and
>
> (ii) Each stationary combustion turbine which is equipped both to fire oil using diffusion flame technology and to fire gas, and is located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil more than an aggregate total of 1,000 hours during the calendar year, during any period when it is firing oil."

Based on this definition, if all (i.e., existing and new) dual fuel CTs at the Stanton Energy Center collectively fire oil (using diffusion flame technology) for more than 1,000 hours during any calendar year, then each CT that commenced construction after January 14, 2003, would be classified as a diffusion flame oil-fired stationary CT when the CT is firing oil and subject to the requirements of Subpart YYYY. Note that Subpart YYYY exempts all existing CTs (i.e., those that commenced construction on or before January 14, 2003).

For diffusion flame oil-fired stationary CTs, Subpart YYYY limits formaldehyde emissions to 91 parts per billion by dry volume (ppbvd) at 15-percent oxygen. This same limit would also apply to lean premix gas-fired units in the event this CT category is not delisted.

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 Unit B CTG/HRSG will be subject to the ARP since it will be a *new utility unit* (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, OUC will need to annually obtain SO_2 allowances from the ARP SO_2 allowance market in amounts equal to the Unit B CTG/HRSG'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 a 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 Unit B CTG/HRSG (i.e., a new source set-aside). Similar to the ARP, there are no provisions for a new source set-aside with respect to CAIR SO_2 allowances. For NO_x allowances, new units will be allocated allowances from the new source set-aside until they have established a baseline and are included in the shared pool. NO_x allowance allocations from the new source set-aside pool will be made to new utility units on a pro-rata basis.

4.5 CLEAN AIR MERCURY RULE

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

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

The NSPS program serves as the regulatory authority for CAMR. Accordingly, the revisions to NSPS Subpart Da were effective upon proposal (i.e., January 30, 2004). CAMR also includes a new NSPS, Subpart HHHH, which contains EPA's model mercury trading program. Under the terms of revised NSPS Subpart Da, states must submit plans by November 17, 2006, that address the state electric generating unit mercury caps for 2010 and 2018 for EPA review and approval. The state plans will provide details as to the procedures that will be used to allocate the state mercury budgets to individual coal-fired utility units. For each control period, sufficient mercury allowances must be held to cover the actual mercury emissions for all mercury budget units at a source. Although mercury allowances will be allocated on a unit-by-unit basis, compliance with the CAMR mercury allowance program is determined on a plantwide 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 Unit B CCCT project. 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 .418, F.A.C., specify emission standards for 18 categories of sources. Sections 62-296.470 and .480 address CAIR and CAMR requirements, respectively. Sections 62-296.500 through .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 .605 and 62-296.700 through .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 Unit B CCCT 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 .418, F.A.C., are applicable to the Unit B CCCT project. The VOC, NO_x, lead, and PM RACT requirements do not apply to emission units that are subject to NSR permitting and, therefore, are not applicable to the Unit B CCCT project. NSPS Subpart KKKK will be applicable to the Unit B CTG/HRSG. In the event Unit B CTG/HRSG ULSD fuel firing occurs for more than 1,000 hours during a calendar year, NESHAPs Subpart YYYY will be applicable.

The Unit B CCCT project will comply with all of the applicable Florida emission standards noted previously herein.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY

5.1 METHODOLOGY

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

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

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

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

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

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

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

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

As shown in Table 3-2 of Section 3.0, annual Unit B CCCT project emissions of NO_x, PM/PM_{10}, CO, SO_2, and H_2SO_4 mist are projected to exceed the PSD significance rates for these pollutants. A BACT analysis is therefore required for each Unit B CCCT project emission unit that will emit these pollutants. Accordingly, BACT analyses were conducted for the Unit B CTG/HRSG and mechanical draft cooling tower.

The CTG/HRSG will emit pollutants associated with fuel combustion including NO_x, PM/PM_{10}, CO, SO_2, and H_2SO_4 mist. BACT analyses were therefore conducted for each of these combustion-related PSD pollutants for the CTG/HRSG unit. The mechanical draft cooling tower will only emit PM/PM_{10}. The BACT analysis for this emission source was therefore confined to PM/PM_{10}.

The CTG/HRSG unit is the principal Unit B CCCT project emission source. The primary fuel for the CTG/HRSG unit will be pipeline-quality natural gas with ULSD fuel oil serving as a backup fuel source. The CTG/HRSG unit will be equipped with a comprehensive state-of-the-art emission control system that includes dry low-NO_x combustors (when firing natural gas), water injection (when firing ULSD fuel oil), and SCR. This system of emission control equipment and use of clean fuels will reduce emissions of the two primary pollutants (SO_2 and NO_x) to levels equal to the lowest rates that have been approved by FDEP for recent similar CCCT projects.

Control technology analyses using the five-step top-down BACT method are provided in Sections 5.2 (NO_x), Section 5.3 (CTG/HRSG unit PM/PM_{10}), Section 5.4 (cooling tower PM/PM_{10}), Section 5.5 (SO_2 and H_2SO_4 mist), and Section 5.6 (CO).

5.2 BACT ANALYSIS FOR NO_X—CTG/HRSG UNIT

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

Thermal NO_x is formed by the high-temperature reaction of nitrogen with oxygen. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed by the relatively fast reaction between nitrogen, oxygen, and hydrocarbon radicals. Prompt NO_x formation is important in lower temperature combustion processes but is much less important compared to thermal NO_x formation at the high temperatures in the CTG.

Fuel NO_x arises from the oxidation of chemically bound nitrogen contained in the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. The conversion of fuel-bound nitrogen (FBN) to NO_x depends on the bound nitrogen content of the fuel. Presently, there are no combustion processes available to control fuel NO_x emissions. For this reason, the gas turbine Subpart GG NSPS, for example, contains an allowance for fuel NO_x. Natural gas and ULSD fuel oil normally contain very little organically bound nitrogen. For these two fuels, the primary contributor to NO_x in the exhaust gas is thermal NO_x.

5.2.1 AVAILABLE NO_X CONTROL TECHNOLOGIES

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

Combustion Process Modifications:

- Water or steam injection.
- Dry low-NO_x combustor design.
- XONON®.

Postcombustion Exhaust Gas Treatment Systems:

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

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

Water or Steam Injection

Injection of water or steam into the primary combustion zone of advanced combustors of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel.

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

The use of water or steam injection in diffusion flame combustors firing natural gas and distillate fuel oil can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd, corrected to 15-percent oxygen, respectively.

Dry Low-NO_x Combustor Design

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

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

XONON®

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

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

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

Selective Noncatalytic Reduction

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

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

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

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

Nonselective Catalytic Reduction

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

Selective Catalytic Reduction

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

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

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

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

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

As is the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO_x emissions.

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

EMx™ (SCONO$_x$™)

EMx™ (formerly referred to as SCONO$_x$™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO$_x$, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to carbon dioxide (CO_2) and NO to NO_2. NO_2 formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:

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

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

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

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

Water vapor and elemental nitrogen are released to the atmosphere as part of the CTG/HRSG exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again.

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

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

For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst.

Utility materials needed for the operation of the EMx™ control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the EMx™ control system is limited to several small CCCT power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low-temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO_x removal efficiency. This facility is no longer operating due to market factors. A high-temperature application of $SCONO_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW Solar CTG located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTGs, there are currently no CCCT units larger than 43 MW that have demonstrated successful application of the EMx™ control technology. In addition, a California study concluded that the capital and annual operating costs for the EMx™ control technology are approximately three times higher than a conventional SCR control system.

5.2.2 TECHNICAL FEASIBILITY AND RANKING

Water or Steam/Diluent Injection

Water or steam injection is a technically feasible technology for CTGs fired with natural gas and distillate fuel oil.

Dry Low-NO_x Combustor Design

Dry low-NO_x combustor technology is an established technology for natural gas-fired CTGs. Due to the combustion characteristics of distillate fuel oil, dry low-NO_x combustor technology is not currently available for oil-fired CTGs.

XONON™

The XONON Cool Combustion® technology is not commercially available for the Unit B GE 7FA CTG. In addition, XONON Cool Combustion® technology has not been demonstrated on large, heavy-duty CTGs. Accordingly, the XONON Cool Combustion® technology is not considered to be a technically feasible control technology for the Unit B CTG.

SNCR

SNCR is not technically feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in the Unit B CTG exhaust gas stream when firing either natural gas or ULSD fuel oil.

NSCR

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

EMx™ (SCONO$_x$)

The EMx™ control technology has not been commercially demonstrated on large CTGs The Unit B CTG/HRSG has a nominal generation capacity of 300 MW. Accordingly, the Unit B CTG/HRSG is approximately seven times larger than the nominal 43-MW CC unit used at the city of Redding power plant facility located in Redding, California. Technical problems associated with scale-up of the EMx™ technology are unknown. Additional concerns with EMx™ control technology include process complexity (multiple catalytic oxidation/absorption/regeneration systems), reliance on only one supplier, and the relatively brief operating history of the technology.

SCR

SCR is an established technology for natural gas and distillate fuel oil-fired CTG/HRSG units and therefore is technically feasible for the Unit B CTG/HRSG.

5.2.3 EVALUATION OF CONTROL TECHNOLOGIES

OUC proposes to install the NO_x control technologies identified as having the highest control efficiency (i.e., dry low-NO_x [for natural gas], water injection [for ULSD fuel oil], and SCR) (see Table 5-1). The economic and energy impacts associated with the installation and operation of this combination of control technologies is considered reasonable. Regarding collateral environmental impacts, use of SCR control technology will result in emissions of ammonia slip. At an ammonia slip concentration of 5.0 ppmvd at 15-percent oxygen, Unit B CTG/HRSG annual ammonia emissions will be 52.6 tpy.

5.2.4 PROPOSED NO_X BACT EMISSION LIMITS

OUC proposes BACT NO_x exhaust concentration limits of 2.0 and 8.0 ppmvd at 15-percent oxygen when firing natural gas and ULSD fuel oil, respectively, on a 24-hour block average basis. At 70°F ambient temperature and 100-percent load with evaporative cooling, these CTG/HRSG unit NO_x exhaust concentrations are equivalent to 12.7 lb/hr, 0.048 lb/MWh (gross), and 0.0072 lb/MMBtu (HHV) for natural gas and 60.3 lb/hr, 0.22 lb/MWh (gross), and 0.031 lb/MMBtu for ULSD fuel oil. The proposed limits represent NO_x emission reductions of 99 and 96 percent for natural gas and ULSD fuel oil, respectively, compared to the estimated uncontrolled NO_x exhaust concentration of 200 ppmvd. The proposed Unit B CTG/HRSG NO_x BACT limits for natural gas and ULSD fuel oil are considered to represent the *top* cases and are consistent with recent FDEP BACT determinations for similar projects (e.g., the FMPA Treasure Coast and FPL West County Energy Center projects).

Table 5-1. Ranking of Available NO_x Control Technologies—CTG/HRSG

Control Technology	Technically Feasible (Yes/No)	Approximate Control Efficiency* (percent)
DLN and SCR (natural gas)	Yes	99
Water injection and SCR (fuel oil)	Yes	96
DLN (natural gas)	Yes	96
SCR	Yes	80 to 90
Water injection (natural gas)	Yes	88
Water injection (fuel oil)	Yes	80
SNCR	No	Not applicable
NSCR	No	Not applicable
EMx™	No	Not applicable
XONON®	No	Not applicable

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

Source: ECT, 2008.

NO_x BACT emission limits proposed for the Unit B CTG/HRSG are summarized as follows:

Natural Gas:

- Emission Limit—2.0 ppmvd at 15-percent oxygen.
- Averaging Period—24-hour block average.
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

ULSD Fuel Oil:

- Emission Limit—8.0 ppmvd at 15-percent oxygen.
- Averaging Period—24-hour block average.
- Compliance Method—Continuous emissions monitoring in accordance with 40 CFR 75.

With respect to excess emissions occurring during periods of startup and shutdown, OUC requests the same permit conditions as specified in the FMPA Treasure Coast Energy Center air construction permit (reference Conditions 15 through 20 of Final Permit No. PSD-FL-353).

5.3 BACT ANALYSIS FOR PM/PM_{10}—CTG/HRSG UNIT

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

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

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

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

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

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

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

Centrifugal Collectors

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

ESPs

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

Fabric Filters

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/PM_{10} is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot (cfm-ft^2). Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

Wet Scrubbers

Wet scrubbers remove PM/PM_{10} from gas streams principally by inertial impaction of the particulate onto a water droplet. Particles can be wetted by impingement, diffusion, or condensation mechanisms. To be wetted, PM/PM_{10} must either make contact with a spray droplet or impinge upon a wet surface. In a venturi scrubber, the gas stream is constricted in a throat section. The large volume of gas passing through a small constriction gives a high gas velocity and a high-pressure drop across the system. As water is introduced into the throat, the gas is forced to move at a higher velocity, causing the water to shear into droplets. Particles in the gas stream then impact onto the water droplets produced. The entrained water droplets are subsequently removed from the gas stream by a cyclone separator. Venturi scrubber collection efficiency increases with increasing pressure drop for a given particle size. Collection efficiency will also increase with increasing liquid-to-gas ratios up to the point where flooding of the system occurs. Packed-bed and venturi scrubber collection efficiencies are typically 90 percent for particles smaller than 2.5 microns in size.

5.3.2 TECHNICAL FEASIBILITY AND RANKING

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTGs, none of the previously described control equipment has been applied to CTGs because exhaust gas PM/PM_{10} concentrations are inherently low. CTGs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The Unit B CTG/HRSG will be fired with natural gas and ULSD fuel oil and will generate low PM/PM_{10} emissions in comparison to other fuels due to their very low ash and sulfur contents. The minor PM/PM_{10} emissions, coupled with a large volume of exhaust gas, produce extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentrations for the Unit B CTG/HRSG at baseload and 70°F are approximately 0.003 and 0.005 grains per dry standard cubic foot (gr/dscf) while firing natural gas and ULSD fuel oil, respectively. Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5.3.3 EVALUATION OF CONTROL TECHNOLOGIES

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

5.3.4 PROPOSED BACT PM/PM_{10} EMISSION LIMITATIONS

Recent Florida BACT determinations for dual fuel CCCT projects are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM/PM_{10} are not appropriate for CTG/HRSG units, the use of good combustion practices and clean fuels is considered to be BACT. The Unit B CTG/HRSG will use the latest combustor technology to maximize combustion efficiency and minimize PM/PM_{10} emission rates. Combustion efficiency, defined as the percentage of fuel completely oxidized in the combustion process, is projected to be greater than 99 percent. The CTG/HRSG unit will be fired with pipeline-quality natural gas and ULSD fuel oil. The high CTG combustion temperatures and use of clean fuels will result in very low PM/PM_{10} emissions.

Due to the difficulties associated with stack testing exhaust streams containing very low PM/PM_{10} concentrations and consistent with recent FDEP BACT determinations for CCCT projects, the use of clean fuels (e.g., pipeline-quality natural gas and ULSD fuel oil) and efficient combustion design and operation is proposed as BACT for PM/PM_{10}. As an indicator of the use of a clean fuels and efficient combustion design and operation, a visible emissions limit of 10-percent opacity is proposed. PM/PM_{10} BACT emission limits for natural gas and ULSD fuel oil proposed for the Unit B CTG/HRSG are summarized as follows:

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

5.4 BACT ANALYSIS FOR PM/PM_{10}—COOLING TOWER

Operation of conventional wet mechanical draft cooling tower operations will result in emissions of PM/PM_{10}. The Unit B CCCT project will include a six-cell cooling tower. Because of direct contact between the cooling water and ambient air, a small portion of the recirculating cooling water is entrained in the air stream and discharged from the cooling tower as drift droplets. These water droplets contain the same concentration of dissolved solids as found in the recirculating cooling water. Large water droplets quickly settle out of the cooling tower exhaust stream and deposit near the tower. The remaining smaller water droplets may evaporate prior to being deposited in the area surrounding the cooling tower. These evaporated droplets represent potential PM/PM_{10} emissions because of the fine PM/PM_{10} formed by crystallization of the dissolved solids contained in the droplet.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

The only feasible technology for controlling PM/PM_{10} from wet cooling towers is the use of drift eliminators. Drift eliminators rely on inertial separation caused by airflow direction changes to remove water droplets from the air stream leaving the tower. The water droplets are returned to the cooling tower. Drift eliminator configurations include herringbone (blade-type), wave-form, and cellular (honeycomb) designs. Drift eliminator materials of construction include ceramics, fiber-reinforced cement, metal, plastic, and wood fabricated into closely spaced slats, sheets, honeycomb assemblies, or tiles.

5.4.2 PROPOSED PM/PM_{10} BACT EMISSION LIMITATIONS

PM/PM_{10} emissions from the Unit B CCCT project cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift rate of no more than 0.0005 percent of the cooling tower recirculating water flow. This cooling tower drift rate is consistent with recent FDEP BACT determinations (i.e., the FMPA Treasure Coast and FPL West County Energy Center projects). PM/PM_{10} BACT proposed for the Unit B CCCT project cooling tower is summarized as follows:

- Emission Limit—Use of high efficiency drift eliminators with a drift rate of no more than 0.0005 percent.
- Compliance Method—Cooling tower manufacturer certification.

5.5 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

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

Fuel Treatment

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

Flue Gas Desulfurization

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

5.5.2 TECHNICAL FEASIBILITY AND RANKING

Treatment of natural gas and fuel oil for sulfur compound removal is conducted by the fuel supplier prior to distribution. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas and ULSD fuel oil sulfur contents have already been reduced to very low levels.

There have been no applications of FGD technology to CTGs fired with natural gas or ULSD fuel oil because these fuels contain very little sulfur. The sulfur content of natural gas, the primary fuel source for the Unit B CTG/HRSG, is much lower than the fuels (e.g., coal) employed in boilers using FGD systems. In addition, CTGs operate with a significant amount of excess air that generates high exhaust gas flow rates. Because FGD SO_2 removal efficiency decreases with decreasing inlet SO_2 concentration, application of an FGD system to a CTG exhaust stream will result in unreasonably low SO_2 removal efficiencies. Due to low SO_2 exhaust stream concentrations, FGD technology is not considered to be technically feasible for CTGs because removal efficiencies would be unreasonably low. Similarly, use of mist eliminators to control H_2SO_4 mist emissions is not technically feasible due to the low CTG/HRSG H_2SO_4 mist exhaust concentrations. For example, the Unit B CTG/HRSG will have an H_2SO_4 mist exhaust concentration of 0.00031 gr/dscf when firing natural gas.

5.5.3 PROPOSED SO_2 AND H_2SO_4 MIST BACT EMISSION LIMITATIONS

Because postcombustion SO_2 and H_2SO_4 mist controls are not applicable, use of low sulfur fuels is considered to represent BACT for the Unit B CTG/HRSG. The Unit B CTG/HRSG will be fired with pipeline-quality natural gas containing no more than 2.0 gr S/100 scf as its primary fuel. ULSD fuel oil containing no more than 0.0015 weight percent sulfur will serve as a backup fuel source for up to 1,000 hr/yr. SO_2 and H_2SO_4 mist BACT emission limits proposed for the Unit B CTG/HRSG are summarized as follows:

Natural Gas:

- Emission Limit—Use of pipeline-quality natural gas containing no more than 2.0 gr S / 100 scf.
- Averaging Period—Not applicable.
- Compliance Method—Fuel monitoring in accordance with 40 CFR 75.

ULSD Fuel Oil:

- Emission Limit—Use of ULSD fuel oil containing no more than 0.0015 weight percent sulfur.
- Averaging Period—Not applicable.
- Compliance Method—Fuel monitoring in accordance with 40 CFR 75.
- Annual Operating Hours—Up to 1,000 hr/yr.

5.6 BACT ANALYSIS FOR CO

5.6.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO from CTG/HRSG units: combustion process design and oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emission rates of CO will generally increase during CTG partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control would also result in an increase in CO emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO emission rates. In general, emissions of NO_x and CO are inversely related (i.e., decreasing NO_x emissions will result in an increase in CO emissions).

CTG combustors are designed to minimize CO formation since CO emissions are indicative of inefficient combustion and unused energy. Due to its high combustion temperatures, a CT essentially functions as a thermal oxidizer achieving inherently low CO emissions.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to CO_2 at temperatures approximately 50 percent lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. For natural gas-fired combined-cycle units, the oxidation catalyst would be located within the HRSG where temperatures range from 450 to 1,100°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed. For natural gas-fired combined-cycle applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO.

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

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. An oxidation catalyst system would be expected to convert up to 90 percent of the CTG exhaust stream SO_2 to sulfite. If ammonia is also present as a result of an SCR control system, sulfite and ammonia will react to form ammonium bisulfate. If ammonia is not present, sulfite will combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of SO_2 and excessive formation of either ammonium bisulfate or H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

5.6.2 TECHNICAL FEASIBILITY AND RANKING

Proper CTG combustor design is considered to be a technically feasible control technology for the Unit B CTG/HRSG for both natural gas and ULSD fuel oil firing. It has been demonstrated in both applications.

Oxidation catalyst technology is also considered technically feasible for natural gas and ULSD fuel oil-fired CT/HRSG units.

5.6.3 PROPOSED CO BACT EMISSION LIMITATIONS

CO emissions from the Unit B CTG/HRSG will be low due to high combustion temperatures, excess air, and turbulence characteristics of the GE 7FA CTG. Accordingly, use of oxidation catalyst to reduce the inherently low CTG/HRSG CO emissions would not be cost-effective. OUC proposes the same CO BACT emission limits for the Unit B CTG/HRSG that FDEP has recently issued for a similar CTG/HRSG project—the FMPA Treasure Coast Energy Project. CO BACT emission limits proposed for the Unit B CTG/HRSG are summarized as follows:

<u>Natural Gas</u>:

- <u>Emission Limits</u>—4.1 ppmvd at 15-percent oxygen normal operation and 7.6 ppmvd at 15-percent oxygen with duct burner firing.
- <u>Averaging Period</u>—Stack test duration.
- <u>Compliance Method</u>—EPA Reference Method 10.

<u>ULSD Fuel Oil</u>:

- <u>Emission Limit</u>—8.0 ppmvd at 15-percent oxygen normal operation and with duct burner firing.
- <u>Averaging Period</u>—Stack test duration.
- <u>Compliance Method</u>—EPA Reference Method 10.

<u>Natural Gas and ULSD Fuel Oil</u>:

- <u>Emission Limit</u>—8.0 ppmvd at 15-percent oxygen.
- <u>Averaging Period</u>—24-hour block.
- <u>Compliance Method</u>—CEMS.
- <u>Emission Limit</u>—6.0 ppmvd at 15-percent oxygen.
- <u>Averaging Period</u>—12-month rolling.
- <u>Compliance Method</u>—CEMS.

5.7 SUMMARY OF PROPOSED BACT

Table 5-2 provides a summary of the BACT proposed for the Unit B CCCT project, including the emission limit, averaging period, and compliance method.

Table 5-2. Summary of Proposed BACT Emission Limits

Emission Unit	Pollutant	Averaging Period	BACT Emission Limit	Compliance Method
CTG/HRSG (Natural gas)	NO_x	24-hour block	2.0 ppmvd at 15-percent oxygen	CEMS
	SO_2 and H_2SO_4 mist	N/A	2.0 gr/100 scf natural gas	Part 75 monitoring
	PM/PM_{10}	6-minute	10-percent opacity	EPA Reference Method 9
	CO	24-hour block	8.0 ppmvd at 15-percent oxygen	CEMS
		12-month rolling	6.0 ppmvd at 15-percent oxygen	CEMS
		Stack test	4.1 ppmvd at 15-percent oxygen (normal operations)	EPA RM 10
			7.6 ppmvd at 15-percent oxygen (with duct burners)	EPA RM 10
CTG/HRSG (ULSD fuel oil)	NO_x	24-hour block	8.0 ppmvd at 15-percent oxygen	CEMS
	SO_2 and H_2SO_4 mist	N/A	0.0015 weight percent sulfur fuel oil	Part 75 monitoring
	PM/PM_{10}	6-minute	10-percent opacity	EPA Reference Method 9
	CO	24-hour block	8.0 ppmvd at 15-percent oxygen	CEMS
		12-month rolling	6.0 ppmvd at 15-percent oxygen	CEMS
		Stack test	8.0 ppmvd at 15-percent oxygen	EPA RM 10
Cooling tower	PM/PM_{10}	N/A	Drift eliminators Drift rate of 0.0005 percent	Cooling tower manufacturer certification

Source: ECT, 2008.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

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

The approach to assessing air quality impacts for a new or modified emission source generally begins by determining the impacts of only the proposed facility. If the impacts of the facility are below specified PSD SILs, no further analysis is required. The PSD Class II SILs were previously presented in Table 3-4. If the impacts of a proposed facility are found to exceed a particular PSD SIL, further analysis considering other existing sources and background pollutant concentrations is required for that SIL.

The approach used to analyze the potential impacts of the Unit B CCCT project, as described in detail in the following subsections, was developed in accordance with accepted practice. Guidance contained in EPA manuals and user's guides was sought and followed. In addition, a proposed modeling protocol for the prior Unit B IGCC project was presented to FDEP for review and comment. FDEP staff subsequently accepted this modeling protocol. The air quality analysis for the Stanton Unit B CCCT project was conducted in accordance with the FDEP approved modeling protocol.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the Unit B CCCT project will have the potential to emit 79.6 tpy of NO_x, 162.9 tpy of CO, 110.2 tpy of PM, 108.9 tpy of PM_{10}, 54.4 tpy of SO_2, 18.6 tpy of VOCs, and 8.3 tpy of H_2SO_4 mist.

Table 3-2 previously provided estimated potential annual emission rates for the Unit B CCCT project. As shown in that table, potential emissions of NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10} are each projected to exceed the applicable PSD significant emission rate (SER) threshold. Potential emissions for the Unit B CCCT project are below the applicable PSD SER levels for all other PSD regulated pollutants. Accordingly, the Unit B CCCT project is subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C., for NO_x, SO_2, CO, H_2SO_4 mist, and PM/PM_{10}. In accordance with current EPA policy, PM_{10} was used as a surrogate with respect to $PM_{2.5}$ impacts.

6.3 MODEL SELECTION AND USE

Air quality models are applied at two levels: screening and refined. At the screening level, models provide conservative estimates of impacts to determine whether more detailed modeling is required. Screening modeling can also be used to identify worst-case operating scenarios for subsequent refined modeling analysis. The refined level consists of techniques that provide more advanced technical treatment of atmospheric processes. Refined modeling requires more detailed and precise input data, but also provides improved estimates of source impacts. For the Unit B CCCT project air quality analyses, the current version of the refined American Meteorological Society (AMS)/EPA regulatory model (AERMOD) modeling system (Version 07026—January 26, 2007), together with 5 years of hour-by-hour National Weather Service (NWS) meteorology, was used to obtain predictions of both short-term periods (i.e., periods equal to or less than 24 hours) and annual average air quality impacts.

Regulatory agency recommended procedures for conducting air quality impact assessments are contained in the EPA's GAQM. In the November 9, 2005, FR, EPA approved the use of AERMOD as a GAQM Appendix A *preferred* model effective December 9, 2005. AERMOD is recommended for use in a wide range of regulatory applications, including both simple and complex terrain. The AERMOD modeling system consists of meteorological and terrain preprocessing programs (AERMET and AERMAP, respectively) and the AERMOD dispersion model.

6.4 MODEL OPTIONS

Procedures applicable to the AERMOD modeling system specified in the latest version of the User's Guide for AERMOD (September 2004), addenda to the User's Guide, AERMOD Implementation Guides, and EPA's November 9, 2005, revisions to the GAQM were followed. In particular, the AERMOD control pathway MODELOPT keyword parameters DFAULT and CONC were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC option specifies the calculation of concentrations. The Stanton Energy Center is located in rural southeastern Orange County. Based on an analysis of land use in the vicinity of Stanton, the site is considered rural for modeling purposes. Accordingly, AERMOD options pertinent to urban areas including increased surface heating (URBANOPT keyword) and pollutant exponential decay (HALFLIFE and DCAYCOEF keywords) were not employed. In addition, the option to use flagpole receptors (FLAGPOLE keyword) was not selected.

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

6.5 NO_2 AMBIENT IMPACT ANALYSIS

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

6.6 TERRAIN CONSIDERATION

The GAQM defines *flat* terrain as terrain equal to the elevation of the stack base, *simple* terrain as terrain lower than the height of the stack top, and *complex* terrain as terrain exceeding the height of the stack being modeled.

Site elevation for the Stanton Energy Center is approximately 70 feet above mean sea level (ft-msl). The Unit B CT/HRSG stack height will be 205 ft above grade elevation.

Accordingly, terrain elevations above approximately 275 ft would be classified as complex terrain. U.S. Geological Survey (USGS) 7.5-minute series topographic maps were examined for terrain features in the Unit B CCCT project impact area (i.e., within an approximate 15-km radius). The topography in the vicinity of Stanton is essentially flat with maximum elevations well below the levels that would constitute complex terrain. Based on this examination, terrain in the vicinity of the site is classified as either flat or simple terrain.

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

6.7 BUILDING WAKE EFFECTS

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

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

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

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

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

The height proposed for the Stanton Unit B CT/HRSG stack (i.e., 205 ft above grade level), as well as all other project emission sources, will be less than the *de minimis* GEP height of 65 meters (213 ft). Since the stack heights of the Unit B CCCT project emission sources will comply with the EPA promulgated final stack height regulations (40 CFR 51), actual project stack heights were used in the modeling analyses.

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. AERMOD evaluates the effects of building downwash based on the plume rise model enhancements (PRIME) building downwash algorithms. For the Unit B CCCT project ambient impact analysis, the complex downwash analysis implemented by AERMOD was performed using the current version of EPA's Building Profile Input Program (BPIP) for PRIME (Version 04274 [September 30, 2004]). The EPA BPIP program was used to determine the area of influence for each building, whether a particular stack is subject to building downwash, the area of influence for directionally dependent building downwash, and finally to generate the specific building dimension data required by the model. BPIP output consists of an array of 36 direction-specific (10 degrees [°] to 360°) building heights (BUILDHGT keyword), lengths (BUILDLEN keyword), widths (BUILDWID keyword), and along-flow (XBADJ keyword) and across-flow (YBADJ keyword) distances for each stack suitable for use as input to AERMOD. Dimensions of the building/structures evaluated for the wake effects were determined from engineering layouts and specifications and are shown in Table 6-1. The buildings are shown in three-dimension in Figure 6-1.

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	 Length (meters)	 Height (meters)
Unit A STG	18.3	43.2	13.5
Unit A cooling tower	38.2	83.0	18.1
Unit 1A HRSG	12.1	47.5	25.6
Unit 2A HRSG	12.1	47.5	25.6
Unit A administration building	18.3	33.2	5.3
Unit B HRSG	11.7	38.2	34.8
Unit B CT	10.3	28.7	9.7
Unit B fan inlet	9.4	18.0	21.3
Unit B cooling tower	35.5	44.3	15.2
Unit B STG	14.2	36.5	9.7
Unit B control building	18.5	33.2	5.1
Unit B ULSD fuel oil storage tank	—	19.5*	12.2
Unit 1 cooling tower	—	93.5*	131.4
Unit 1 boiler	55.6	78.5	68.6
Unit 2 cooling tower	—	93.5*	131.4
Unit 2 boiler	51.7	80.8	68.6
Unit 2 precipitator	37.4	56.8	33.5
Air quality control building for Unit 2	54.3	67.2	32.0
STG for Units 1 and 2	32.4	158.0	30.5

*Diameter.

Sources: SCS, 2008
ECT, 2008

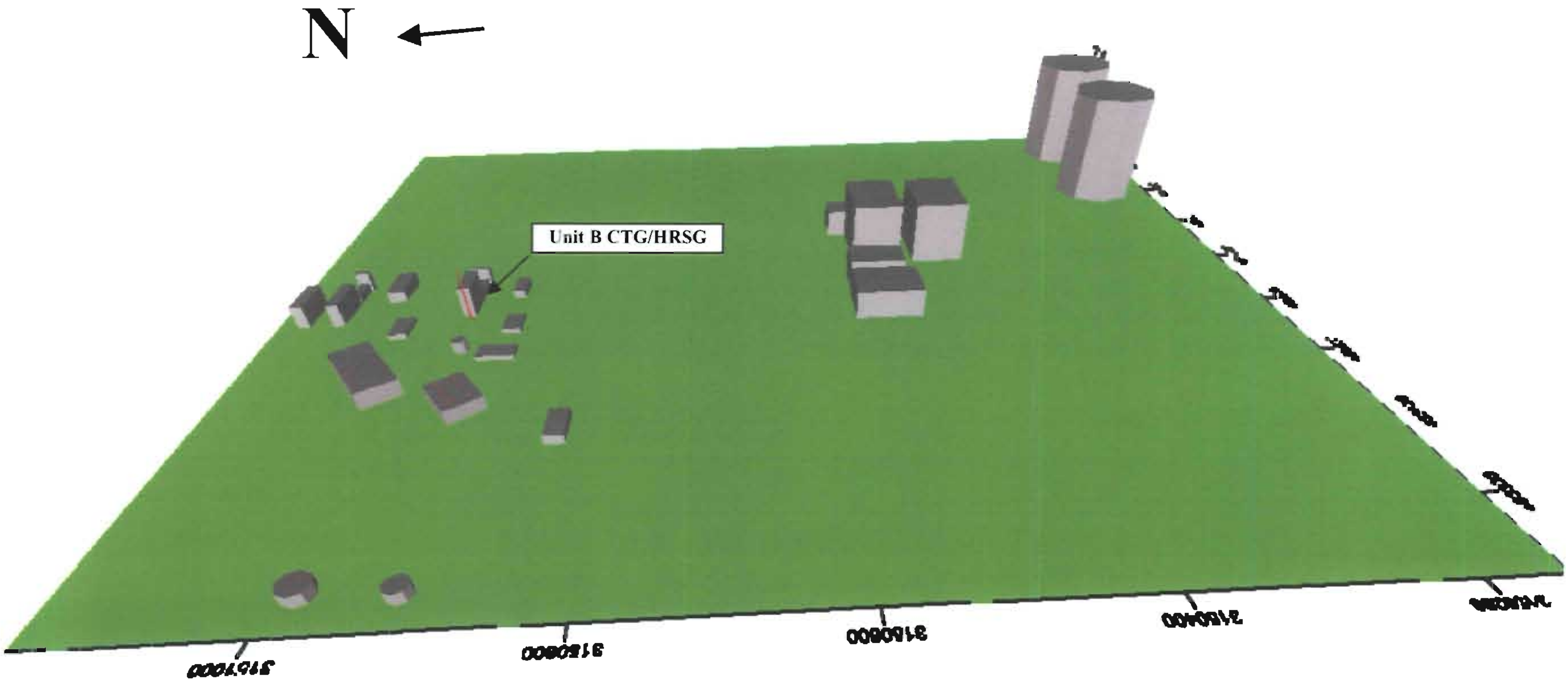

FIGURE 6-1.

BUILDINGS USED IN DOWNWASH ANALYSIS

Source: ECT, 2008.

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6.8 RECEPTOR GRIDS

Receptors were placed at locations considered to be ambient air, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." The entire perimeter of the Stanton Energy Center is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

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

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

Figure 6-2 illustrates a graphical representation of the near-field receptor grids (out to a distance of 3 km). A depiction of the mid- and far-field receptor grids (from 3 to 15 km) is shown in Figure 6-3.

6.9 METEOROLOGICAL DATA

The AERMET meteorological preprocessing program creates two files that are used by AERMOD (i.e., surface and profile files). The surface file contains boundary layer parameters including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, convectively generated boundary layer (CBL) height, stable boundary layer (SBL) height, and surface heat flux. The profile file contains multilevel data of windspeed, wind direction, and temperature.

AERMET calculates the hourly boundary layer parameters for use by AERMOD, including friction velocity, Monin-Obukhov length, convective velocity scale, temperature scale, CBL and SBL heights, and surface heat flux. In addition, AERMET passes all

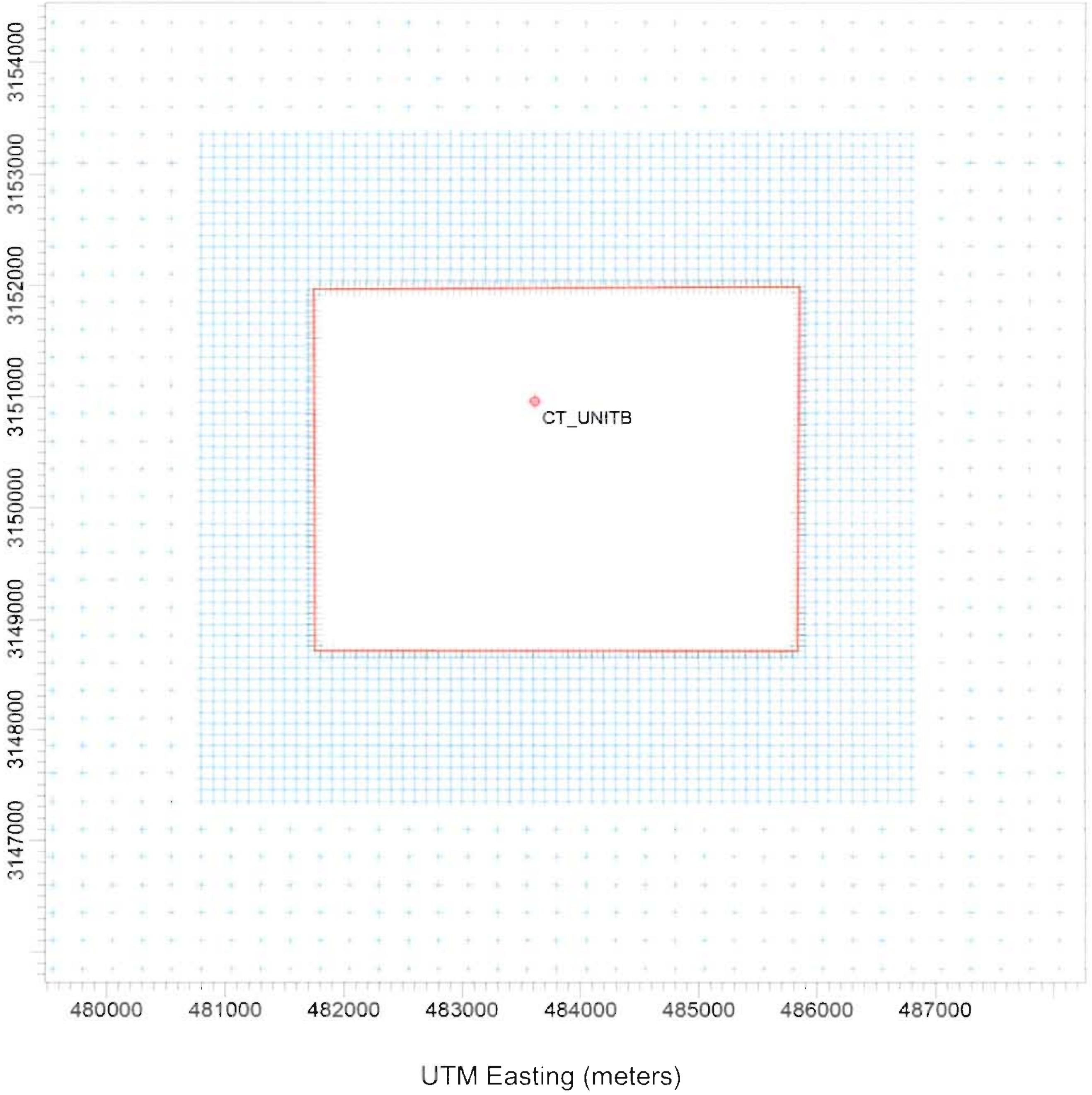

FIGURE 6-2.

NEAR-FIELD RECEPTOR GRID

Source: ECT, 2006.

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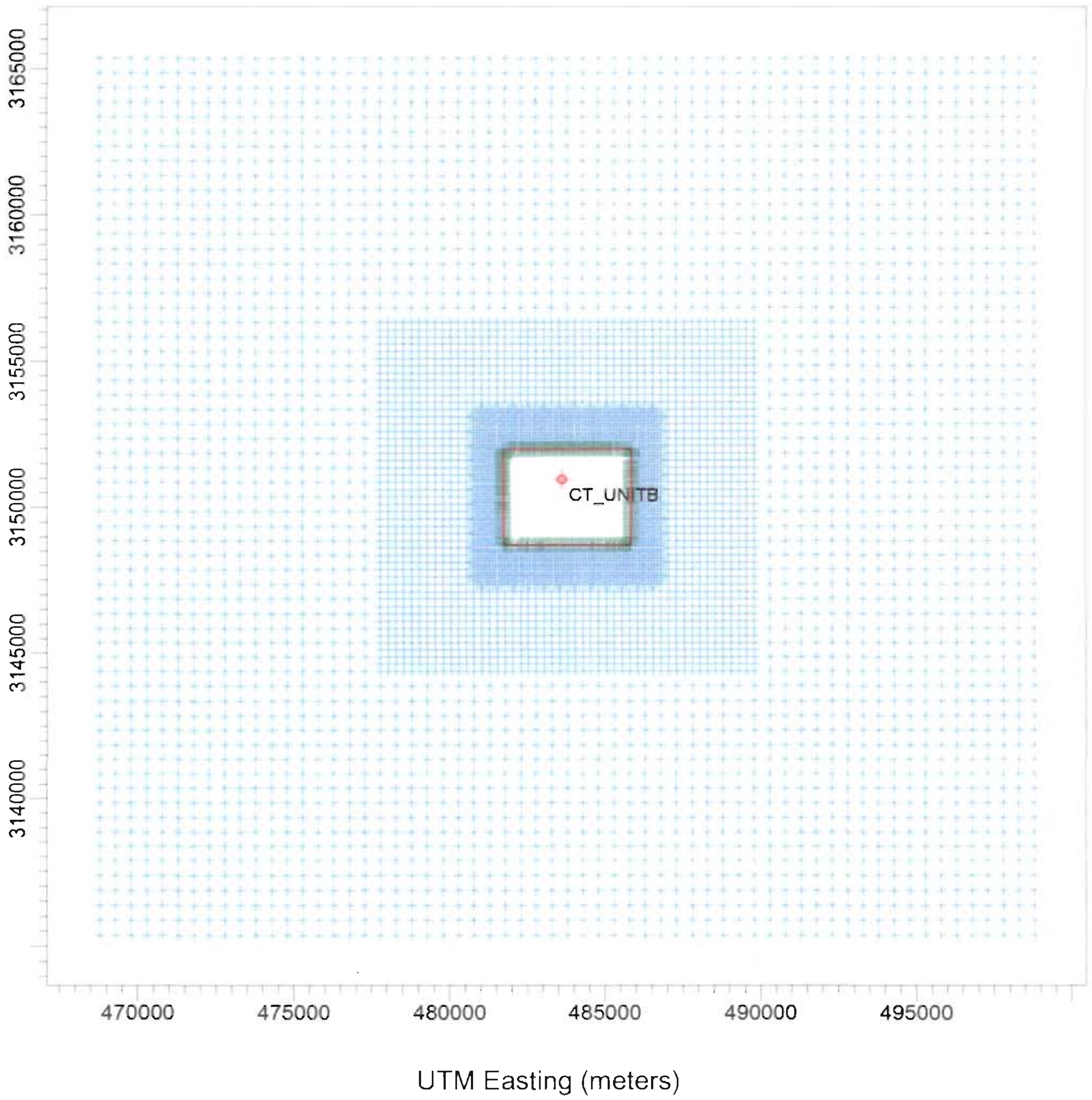

FIGURE 6-3.

FULL RECEPTOR GRID

Source: ECT, 2006.

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observed meteorological parameters to AERMOD including wind direction and speed (at multiple heights, if available), temperature, and if available, measured turbulence. AERMOD uses this information to calculate concentrations in a manner that accounts for a dispersion rate that is a continuous function of meteorology.

Consistent with the GAQM and FDEP guidance, modeling should be conducted using the most recent, readily available, 5 years of meteorological data collected at a nearby observation station. In accordance with this guidance, 5 years (1999 to 2003) of surface and upper air data from the NWS stations (WBAN No. 12815) located at Orlando International Airport (MCO) and Tampa Bay/Ruskin (WBAN No. 12842), respectively, were used for the Unit B CCCT project air quality impact analysis. The AERMET processed meteorological data for these stations was obtained from FDEP.

6.10 MODELED EMISSION INVENTORY

6.10.1 ON-PROPERTY SOURCES

The modeled on-property emission sources consisted of the Unit B CTG/HRSG and mechanical draft cooling tower. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the Unit B CCCT project resulted in air quality impacts below the significance impact levels (reference Table 3-4) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

During normal operations, the CTG/HRSG unit will operate over a range of loads (50 to 100 percent) and ambient temperatures (20 to 95°F) and will utilize two fuels (natural gas and ULSD fuel oil). Appendix A, Table A-2 provides a summary of the Unit B CTG/HRSG operating cases evaluated. Plume dispersion and, therefore, ground-level impacts, will be affected by these different operating scenarios since emission rates, exit temperatures, and exhaust gas velocities will change. For NO_x, CO, and PM_{10}, the highest emission rates will occur when the Unit B CTG/HRSG is fired with ULSD fuel oil. For SO_2, maximum emissions will occur when the CTG/HRSG unit is fired with natural gas based on the FDEP recommended natural gas sulfur content of 2.0 gr S/100 scf. To simplify the modeling analysis, the pollutant emission rates, stack velocities, and stack temperatures were *enveloped* for both the ULSD fuel oil and natural gas CTG/HRSG operating cases to conservatively develop maximum air quality impacts (i.e., the maximum emission rates and minimum stack velocities and temperatures for all operating cases for each fuel type were used). The specific emission rates and stack data used for both natural gas and ULSD fuel oil are summarized as follows:

Stack Temperature (°F)	Stack Velocity (ft/sec)	NO_x (lb/hr)	CO (lb/hr)	SO_2 (lb/hr)	PM_{10} (lb/hr)
202.9	34.6	65.4	39.8	12.4	34.6

Emissions rates and stack parameters for the Unit B CCCT project were previously presented in Tables 2-1 through 2-8.

6.10.2 OFF-PROPERTY SOURCES

Since the Unit B CCCT project maximum air quality impacts were below the PSD SILs for all PSD pollutants, a full, multisource interactive assessment of NAAQS attainment and PSD Class II increment consumption was not required.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 OVERVIEW

Comprehensive dispersion modeling was conducted to assess the air quality impacts resulting from Unit B CCCT project operations in accordance with the methodology described in Section 6.0. This section provides the results of the Unit B CCCT project Class II air quality assessment for SO_2, NO_2, CO, and PM_{10}. Unit B CCCT project air quality impacts at distant PSD Class I areas resulting from long-range transport are addressed in Section 10.0.

As previously discussed in Section 6.0, pollutant emission rates, and stack velocities and temperatures were enveloped for both the ULSD fuel oil and natural gas CTG/HRSG operating cases to conservatively develop maximum air quality impacts (i.e., the maximum emission rates and minimum stack velocities and temperatures for all operating cases for each fuel type were used). This modeling approach for the Unit B CTG/HRSG is conservative (i.e., will overestimate air quality impacts). Maximum impacts will be overestimated since the enveloped modeled CTG/HRSG operating cases represent conditions that will not occur (i.e., maximum emission rates at low-load operation and 95°F ambient temperature).

In addition to the Unit B CTG/HRSG, the Class II air quality analysis also included PM_{10} emissions from the Unit B CCCT project cooling tower

7.2 PSD SIL ANALYSIS RESULTS

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

Detailed Unit B CCCT project AERMOD results for each year of meteorology are summarized in Table 7-1 (NO_2); Tables 7-2, 7-3, and 7-4 (SO_2); Table 7-5 and 7-6 (PM_{10});

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

Maximum Annual Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.0239	0.0230	0.0287	0.0289	0.0319
Unit B CT/HRSG Emission Rate (g/s)	8.24	8.24	8.24	8.24	8.24
Tier 1 Impact ($\mu g/m^3$)†	0.197	0.190	0.236	0.238	0.263
Tier 2 Impact ($\mu g/m^3$)‡	0.148	0.142	0.177	0.179	0.197
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	14.8	14.2	17.7	17.9	19.7
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	14.0	14.0	14.0
Exceed PSD de minimis Ambient Impact (Yes/No)	No	No	No	No	No
Receptor UTM Easting (meters)	483,676	483,874	483,676	483,577	483,626
Receptor UTM Northing (meters)	3,151,976	3,151,976	3,151,976	3,151,975	3,151,975
Distance From Unit B CTG/HRSG (meters)	1,022	1,053	1,022	1,021	1,020
Direction From Unit B CTG/HRSG (Vector °)	3	14	3	358	1

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CT/HRSG emission rate (assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 2008.

Table 7-2. AERMOD Model Results—Maximum Annual Average SO_2 Impacts

Maximum Annual Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.0239	0.0230	0.0287	0.0289	0.0319
Unit B CT/HRSG Emission Rate (g/s)	1.57	1.57	1.57	1.57	1.57
Adjusted Impact ($\mu g/m^3$)†	0.037	0.036	0.045	0.045	0.050
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	3.7	3.6	4.5	4.5	5.0
Receptor UTM Easting (meters)	483,676	483,874	483,676	483,577	483,626
Receptor UTM Northing (meters)	3,151,976	3,151,976	3,151,976	3,151,975	3,151,975
Distance From Unit B CTG/HRSG (meters)	1,022	1,053	1,022	1,021	1,020
Direction From Unit B CTG/HRSG (Vector °)	3	14	3	358	1

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2008.

Table 7-3. AERMOD Model Results—Maximum 3-Hour Average SO_2 Impacts

Maximum 3-Hour Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.877	0.727	0.746	0.687	0.707
Unit B CT/HRSG Emission Rate (g/s)	1.57	1.57	1.57	1.57	1.57
Adjusted Impact ($\mu g/m^3$)†	1.37	1.14	1.17	1.08	1.11
PSD Significant Impact ($\mu g/m^3$)	25.0	25.0	25.0	25.0	25.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	5.5	4.5	4.7	4.3	4.4
Receptor UTM Easting (meters)	483,280	483,230	483,725	483,626	483,500
Receptor UTM Northing (meters)	3,151,974	3,151,974	3,151,976	3,151,975	3,152,250
Distance From Unit B CTG/HRSG (meters)	1,073	1,089	1,027	1,020	1,300
Direction From Unit B CTG/HRSG (Vector °)	342	339	6	1	355
Date of Maximum Impact	01/23/99	09/17/00	03/12/01	03/0302	02/22/03
Ending Hour of Maximum Impact	2100	2100	2400	0900	0600

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2008.

Table 7-4. AERMOD Model Results—Maximum 24-Hour Average SO_2 Impacts

Maximum 24-Hour Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact (μg/m^3)*	0.331	0.229	0.318	0.262	0.220
Unit B CT/HRSG Emission Rate (g/s)	1.57	1.57	1.57	1.57	1.57
Adjusted Impact (μg/m^3)†	0.52	0.36	0.50	0.41	0.34
PSD Significant Impact (μg/m^3)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	10.4	7.2	10.0	8.2	6.9
PSD *de minimis* Ambient Impact Threshold (μg/m^3)	13.0	13.0	13.0	13.0	13.0
Exceed PSD de minimis Ambient Impact (Yes/No)	No	No	No	No	No
Percent of PSD *de minimis* Ambient Impact (%)	4.0	2.8	3.8	3.2	2.7
Receptor UTM Easting (meters)	483,428	481,750	483,676	483,379	483,775
Receptor UTM Northing (meters)	3,151,974	3,150,782	3,151,976	3,151,974	3,151,976
Distance From Unit B CTG/HRSG (meters)	1,036	1,874	1,022	1,047	1,033
Direction From Unit B CTG/HRSG (Vector °)	350	265	3	347	9
Date of Maximum Impact	01/02/99	03/18/00	07/23/01	12/31/02	06/03/03

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CT/HRSG emission rate.

Source: ECT, 2008.

Table 7-5. AERMOD Model Results—Maximum Annual Average PM_{10} Impacts

Maximum Annual Impacts	1999	2000	2001	2002	2003
AERMOD Impact (µg/m3)*	0.1070	0.1028	0.1284	0.1295	0.1425
PSD Significant Impact (µg/m^3)	1.0	1.0	1.0	1.0	1.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	10.7	10.3	12.8	13.0	14.2
Receptor UTM Easting (meters)	483,626	483,874	483,676	483,577	483,626
Receptor UTM Northing (meters)	3,151,975	3,151,976	3,151,976	3,151,975	3,151,975
Distance From Unit B CTG/HRSG (meters)	1,020	1,053	1,022	1,021	1,020
Direction From Unit B CTG/HRSG (Vector °)	1	14	3	358	1

*Impact for all Unit B PM_{10} emission sources.

Source: ECT, 2008.

Table 7-6. AERMOD Model Results—Maximum 24-Hour Average PM$_{10}$ Impacts

Maximum 24-Hour Impacts	1999	2000	2001	2002	2003
AERMOD Impact (µg/m3)*	1.459	1.009	1.412	1.162	0.971
PSD Significant Impact (µg/m^3)	5.0	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	29.2	20.2	28.2	23.2	19.4
PSD *de minimis* Ambient Impact Threshold (µg/m^3)	10.0	10.0	10.0	10.0	10.0
Exceed PSD de minimis Ambient Impact (Yes/No)	No	No	No	No	No
Receptor UTM Easting (meters)	483,428	481,750	483,676	483,428	483,725
Receptor UTM Northing (meters)	3,151,974	3,150,782	3,151,976	3,151,974	3,151,976
Distance From Unit B CTG/HRSG (meters)	1,036	1,874	1,022	1,036	1,027
Direction From Unit B CTG/HRSG (Vector °)	350	265	3	350	6
Date of Maximum Impact	01/02/99	03/18/00	07/23/01	03/02/02	06/03/03

*Impact for all Unit B PM$_{10}$ emission sources.

Source: ECT, 2008.

and Tables 7-7 and 7-8 (CO). These tables provide maximum Unit B CCCT project impacts, the locations of these impacts, and relevant regulatory criteria.

Table 7-9 summarizes maximum Unit B CCCT project air quality impacts using AERMOD and the enveloped operating cases. The AERMOD results presented in Table 7-9 demonstrate that Unit B CCCT project air quality impacts for all pollutants and averaging periods will be below the PSD SILs previously shown in Table 3-4. As previously noted, the Class II impact results overestimate actual air quality impacts due to the conservative modeling approach taken.

7.3 OZONE IMPACTS

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

Unit B CCCT project estimated potential NO_x and VOC emissions are 79.6 and 18.6 tpy, respectively. These annual emission rates are both less than 100 tpy, and therefore an ambient air quality analysis for ozone is not required. The Unit B CCCT project annual emission rates are also relatively minor in comparison to regional emissions. For example, total Orange County NO_x and VOC emissions in 1999 were 41,952 and 43,828 tons, respectively. Accordingly, Unit B CCCT project potential NO_x and VOC emissions will be only 0.2 and 0.04 percent of total 1999 Orange County NO_x and VOC emissions, respectively.

Ambient ozone levels in Orange County are primarily due to ozone transport from upwind areas and regional NO_x and VOC emissions resulting from motor vehicle activity. In 1999, motor vehicle NO_x and VOC emissions comprised 76.5 and 71.3 percent, respectively, of total Orange County NO_x and VOC emissions. Despite significant increases in population and motor vehicle activity, ambient ozone air quality in Orange

Table 7-7. AERMOD Model Results—Maximum 1-Hour Average CO Impacts

Maximum 1-Hour Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact (µg/m^3)*	1.030	0.977	1.013	0.988	0.967
Unit B CTG/HRSG Emission Rate (g/s)	5.0	5.0	5.0	5.0	5.0
Adjusted Impact (µg/m^3)†	5.2	4.9	5.1	5.0	4.8
PSD Significant Impact (µg/m^3)	2,000.0	2,000.0	2,000.0	2,000.0	2,000.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	0.3	0.2	0.3	0.2	0.2
Receptor UTM Easting (meters)	483,725	483,379	483,527	483,280	483,428
Receptor UTM Northing (meters)	3,151,976	3,151,974	3,151,975	3,151,974	3,151,974
Distance From Unit B CTG/HRSG (meters)	1,027	1,047	1,024	1,073	1,036
Direction From Unit B CTG/HRSG (Vector °)	6	347	355	342	350
Date of Maximum Impact	06/15/99	09/17/00	06/13/01	05/30/02	04/26/03
Ending Hour of Maximum Impact	2000	2100	2000	2100	0500

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CTG/HRSG emission rate.

Source: ECT, 2008.

Table 7-8. AERMOD Model Results—Maximum 8-Hour Average CO Impacts

Maximum 8-Hour Impacts	1999	2000	2001	2002	2003
Unadjusted AERMOD Impact ($\mu g/m^3$)*	0.697	0.489	0.507	0.521	0.545
Unit B CTG/HRSG Emission Rate (g/s)	5.0	5.0	5.0	5.0	5.0
Adjusted Impact ($\mu g/m^3$)†	3.50	2.5	2.54	2.61	2.73
PSD Significant Impact ($\mu g/m^3$)	500.0	500.0	500.0	500.0	500.0
Exceed PSD Significant Impact (Yes/No)	No	No	No	No	No
Percent of PSD Significant Impact (%)	0.7	0.5	0.5	0.5	0.5
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	575.0	575.0	575.0	575.0	575.0
Exceed PSD *de minimis* Ambient Impact (Yes/No)	No	No	No	No	No
Percent of PSD *de minimis* Ambient Impact (%)	0.6	0.4	0.4	0.5	0.5
Receptor UTM Easting (meters)	483,478	483,626	483,626	483,874	483,626
Receptor UTM Northing (meters)	3,151,975	3,151,975	3,151,975	3,151,976	3,151,975
Distance From Unit B CTG/HRSG (meters)	1,029	1,020	1,020	1,053	1,020
Direction From Unit B CTG/HRSG (Vector °)	352	1	1	14	1
Date of Maximum Impact	01/02/99	11/07/00	10/14/01	03/03/02	05/06/03
Ending Hour of Maximum Impact	2400	1600	1600	1600	1600

*Based on modeled emission rate of 1.0 g/s.

†Unadjusted AERMOD impact times Unit B CTG/HRSG emission rate.

Source: ECT, 2008.

Table 7-9. AERMOD Model Results Summary

Pollutant	Averaging Time	Maximum Impact (µg/m^3)	PSD Class II Significant Impact (µg/m^3)	Percent of Significant Impact (µg/m^3)
NO_2	Annual	0.197	1.0	19.7
SO_2	Annual	0.050	1.0	5.0
	24-Hour	0.52	5.0	10.4
	3-Hour	1.37	25.0	5.5
PM/PM_{10}	Annual	0.142	1.0	14.2
	24-Hour	1.46	5.0	29.2
CO	8-Hour	5.16	500.0	1.0
	1-Hour	3.50	2000.0	0.2

Source: ECT, 2008.

County has improved over the last 5 years due to improvements in motor vehicle emission rates. For example, the 4th highest 8-hour average ozone concentration at the Winegard Road monitoring station in Orlando was 0.083 part per billion (ppb) in 2000 and 0.079 ppb in 2006. Continued reductions in average motor fleet emissions would be expected to further improvement Orange County ozone air quality. In addition, the CAIR will result in significant actual reductions in existing power plant NO_x emissions throughout Florida.

In summary, the relatively minor NO_x and VOC emissions associated with the Unit B CCCT project will not significantly impact ambient ozone levels in Orange County. Orange County is projected to remain in compliance with the ozone ambient quality standard due to the continued significant reductions in regional motor vehicle and power plant emissions.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air quality monitoring station is located on North Primrose Avenue in Orlando, Orange County, approximately 19 km northwest of the Stanton Energy Center. This station monitors the ambient air for PM_{10} and $PM_{2.5}$. The nearest ambient air quality monitoring station that monitors for 1- and 8-hour average ozone is located on Winegard Road in Orlando, approximately 21 km west of the project site. The nearest NO_2 ambient air quality monitoring station is located at the intersection of Morse Boulevard and Denning Street in Winter Park, Orange County, approximately 23 km northwest of the project site. The nearest CO ambient air quality monitoring station is located on Orange Avenue in Orlando, approximately 21 km northwest of the project site. The nearest ambient air quality monitoring station for lead is situated in Tampa, Hillsborough County, approximately 150 km west of the Stanton Energy Center. All of the Orange County ambient air quality monitoring stations are operated by the Orange County Environmental Protection Division (OCEPD). The Hillsborough County site that monitors ambient air for lead is operated by the Hillsborough County Environmental Protection Commission (HCEPC). Table 8-1 provides summaries of the 2002 through 2006 ambient air quality data for these monitoring stations.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 3.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several PSD pollutants will be emitted from the Unit B CCCT project in excess of their respective significant emission rates, preconstruction monitoring is required. However, Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 3-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the Unit B CCCT project.

Table 8-1. Orlando Area Ambient Air Quality Data Summary—2002 through 2006 (Page 1 of 4)

	Site Location									Ambient Concentration (µg/m³)				
Pollutant	County	City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
PM_{10}	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	24-Hr	60	33	30		150[a]	22.0
							2003	24-Hr	61	30	28		150[a]	20.0
							2004	24-Hr	56	41	27		150[a]	27.3
							2005	24-Hr	61	58	34		150[a]	38.7
							2006	24-Hr	61	38	35		150[a]	25.3
							2002	Annual	60			17	50[b]	34.0
							2003	Annual	61			18	50[b]	36.0
							2004	Annual	56			18	50[b]	36.0
							2005	Annual	61			17.2	50[b]	34.4
							2006	Annual	61			19.2	50[b]	38.4
PM_{10}	Orange	Orlando	North Primrose Avenue	120951004	19	295	2002	24-Hr	61	35	31		150[a]	23.3
							2003	24-Hr	61	56	47		150[a]	37.3
							2004	24-Hr	59	41	36		150[a]	27.3
							2005	24-Hr	61	52	34		150[a]	34.7
							2006	24-Hr	63	42	38		150[a]	28.0
							2002	Annual	61			18	50[b]	36.0
							2003	Annual	61			20	50[b]	40.0
							2004	Annual	59			19	50[b]	38.0
							2005	Annual	61			17.9	50[b]	35.8
							2006	Annual	63			20.5	50[b]	41.0
PM_{10}	Orange	Orlando	Sherrif's Department	120950007	24	278	2002	24-Hr	61	41	38		150[a]	27.3
							2003	24-Hr	59	39	37		150[a]	26.0
							2002	Annual	61			23	50[b]	46.0
							2003	Annual	59			21	50[b]	42.0
PM_{10}	Brevard	Titusville	Tico Airport	120090004	37	84	2002	24-Hr	334	66	38		150[a]	44.0
							2003	24-Hr	354	170	79		150[a]	113.3
							2004	24-Hr	334	61	46		150[a]	40.7
							2005	24-Hr	6908	60	48		150[a]	40.0
							2002	Annual	334			17	50[b]	34.0
							2003	Annual	354			19	50[b]	38.0
							2004	Annual	334			17	50[b]	34.0
							2005	Annual	6908				50[b]	

Table 8-1. Orlando Area Ambient Air Quality Data Summary—2002 through 2006 (Page 2 of 4)

	Site Location									Ambient Concentration (µg/m³)				
Pollutant	County	City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
$PM_{2.5}$	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	24-Hr	353	26	25		65[a]	40.0
							2003	24-Hr	357	23	22		65[a]	35.4
							2004	24-Hr	326	28	26		65[a]	43.1
							2005	24-Hr	345	46.4	42		65[a]	71.4
							2006	24-Hr	343	34.8	25.3		65[a]	53.5
							2002	Annual	353			9.5	15[b]	63.3
							2003	Annual	357			9.3	15[b]	62.0
							2004	Annual	326			9.9	15[b]	66.0
							2005	Annual	345			9.67	15[b]	64.5
							2006	Annual	343			9.33	15[b]	62.2
$PM_{2.5}$	Orange	Orlando	North Primrose Avenue	120951004	19	295	2002	24-Hr	349	30	27		65[a]	46.2
							2003	24-Hr	345	23	21		65[a]	35.4
							2004	24-Hr	307	38	26		65[a]	58.5
							2005	24-Hr	343	45.2	42		65[a]	69.5
							2006	24-Hr	324	34.8	25.3		65[a]	53.5
							2002	Annual	349			9.7	15[b]	64.7
							2003	Annual	345			9.4	15[b]	62.7
							2004	Annual	307			10.1	15[b]	67.3
							2005	Annual	343			9.79	15[b]	65.3
							2006	Annual	324			9.33	15[b]	62.2
SO_2	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	3-Hr	8,571	34.0	28.7		1,300[c]	2.6
							2003	3-Hr	8,647	31.3	28.7		1,300[c]	2.4
							2004	3-Hr	8,324	36.6	23.5		1,300[c]	2.8
							2005	3-Hr	8,493	0.011	0.009		1,300[c]	0.0
							2006	3-Hr	8.563	0.01	0.009		1,300[c]	0.0
							2002	24-Hr	8,571	13.1	13.1		365[c]	3.6
							2003	24-Hr	8,647	15.7	10.4		365[c]	4.3
							2004	24-Hr	8,324	13.1	13.1		365[c]	3.6
							2005	24-Hr	8,493	0.004	0.003		365[c]	0.0
							2006	24-Hr	8,563	0.003	0.003		365[c]	0.0
							2002	Annual	8,571			2.6	80[b]	3.3
							2003	Annual	8,647			2.6	80[b]	3.3

Table 8-1. Orlando Area Ambient Air Quality Data Summary—2002 through 2006 (Page 3 of 4)

Pollutant	Site Location		Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	Ambient Concentration (µg/m³)				
	County	City								1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
							2004	Annual	8,324			2.6	80[b]	3.3
							2005	Annual	8,493			0.0012	80[b]	0.0
							2006	Annual	8,563			0.0012	80[b]	0.0
NO_2	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	Annual	8,485			20.7	100[b]	20.7
							2003	Annual	8,437			20.7	100[b]	20.7
							2004	Annual	8,418			18.8	100[b]	18.8
							2005	Annual	8,569			0.0086	100[b]	0.0
							2006	Annual	8,496			0.0085	100[b]	0.0
CO	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	1-Hr	8,619	4,343	4,000		40,000[c]	10.9
							2003	1-Hr	8,667	2,971	2,629		40,000[c]	7.4
							2004	1-Hr	8,460	2,743	2,743		40,000[c]	6.9
							2005	1-Hr	8,596	2,514	2,400		40,000[c]	6.3
							2006	1-Hr	8,643	2,857	2,629		40,000[c]	7.1
							2002	8-Hr	8,619	3,200	2,857		10,000[c]	32.0
							2003	8-Hr	8,667	1,714	1,714		10,000[c]	17.1
							2004	8-Hr	8,460	1,829	1,829		10,000[c]	18.3
							2005	8-Hr	8,596	2,286	2,057		10,000[c]	22.9
							2006	8-Hr	8,643	1,943	1,714		10,000[c]	19.4
CO	Orange	Orlando	Orange Avenue	120951005	21	289	2002	1-Hr	8,530	5,143	5,029		40,000[c]	12.9
							2003	1-Hr	8,551	3,886	3,657		40,000[c]	9.7
							2004	1-Hr	8,596	4,686	3,086		40,000[c]	11.7
							2005	1-Hr	8,674	9,829	8,914		40,000[c]	24.6
							2006	1-Hr	8,466	3,429	2,629		40,000[c]	8.6
							2002	8-Hr	8,530	3,314	2,857		10,000[c]	33.1
							2003	8-Hr	8,551	2,286	2,286		10,000[c]	22.9
							2004	8-Hr	8,596	2,171	2,057		10,000[c]	21.7
							2005	8-Hr	8,674	5,943	2,971		10,000[c]	59.4
							2006	8-Hr	8,466	1,829	1,714		10,000[c]	18.3
Ozone	Orange	Winer Park	Morris Boulevard	120952002	23	306	2002	1-Hr	237	208	196		235[d]	88.4
							2003	1-Hr	244	186	178		235[d]	79.2
							2004	1-Hr	233	178	174		235[d]	75.9
							2005	1-Hr	244	208	204		235[d]	88.4
							2006	1-Hr	244	192	1,881		235[d]	81.7

Table 8-1. Orlando Area Ambient Air Quality Data Summary—2002 through 2006 (Page 4 of 4)

	Site Location									Ambient Concentration ($\mu g/m^3$)				
Pollutant	County	City	Site Name	Site Number	Distance From Site (km)	Direction From Site (Vector °)	Year	Averaging Period	Number of Observations	1st High	2nd High	Arithmetic Mean	Standard	Percent of Standard
							2002	8-Hr*	237	153	149		157[e]	97.3
							2003	8-Hr*	244	149	145		157[e]	94.8
							2004	8-Hr*	233	151	149		157[e]	96.1
							2005	8-Hr*	243	178	174		157[e]	113.6
							2006	8-Hr*	242	172	161		157[e]	109.8
Ozone	Orange	Orlando	Winegard Road	120950008	21	262	2002	1-Hr	228	206	200		235[d]	87.5
							2003	1-Hr	244	182	174		235[d]	77.5
							2004	1-Hr	163	194	184		235[d]	82.5
							2005	1-Hr	242	235	223		235[d]	100.0
							2006	1-Hr	245	200	174		235[d]	85.0
							2002	8-Hr*	228	147	145		157[e]	93.6
							2003	8-Hr*	244	145	145		157[e]	92.3
							2004	8-Hr*	163	147	145		157[e]	93.6
							2005	8-Hr*	238	192	182		157[e]	122.3
							2006	8-Hr*	242	163	161		157[e]	103.6
Lead	Orange	Winer Park	Morris Boulevard	120952002	23	306	1994-96	24-Hr	182	0.0	0		1.5[b]	0.0
Lead	Orange	Orlando	Sherrif's Department	120950007	24	278	1994-96	24-Hr	182	0.00	0		1.5[b]	0.0

[a] 98th percentile

[b] Arithmetic mean

[c] 2nd high

[d] 4th highest day with hourly value exceeding standard over a 3-year period

[e] 4th highest daily maximum 8-hour concentation over a 3-year period.

* Monitor values represent 3rd and 4th highest 8-hour concentrations.

Sources: FDEP, 2005.
EPA, 2005.
ECT, 2005.

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

8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 1.5 $\mu g/m^3$. This concentration is below the 10-$\mu g/m^3$ *de minimis* level ambient impact level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.2.2 SO_2

The maximum 24-hour SO_2 impact was predicted to be 0.52 $\mu g/m^3$. This concentration is below the 13-$\mu g/m^3$ *de minimis* ambient impact level for the 24-hour averaging period. Therefore, a preconstruction monitoring exemption for SO_2 is appropriate in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.2 $\mu g/m^3$. This concentration is below the 14-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

8.2.4 CO

The maximum 8-hour CO impact was predicted to be 5.2 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for CO in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSIS

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

9.1 GROWTH IMPACT ANALYSIS

9.1.1 PROJECT GROWTH IMPACTS

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

Impacts associated with construction of the Unit B CCCT project will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The Unit B CCCT project is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the project are anticipated. When operational, the Unit B CCCT project is projected to generate an average of 175 new jobs (with a peak of 300 workers) during construction. Following construction, the Unit B CCCT project will employ approximately 20 fulltime employees This number of new personnel will not significantly affect growth in the area. The increase in natural gas and ULSD fuel oil demand due to the operation of the Unit B CCCT project will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.1.2 AREA GROWTH SINCE 1977

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

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

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

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

9.2 IMPACTS ON SOILS, VEGETATION, AND WILDLIFE

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

9.2.1 IMPACTS ON SOILS

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

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

9.2.2 IMPACTS ON VEGETATION

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

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

9.2.3 IMPACTS ON WILDLIFE

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

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

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

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

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

In conclusion, it is unlikely the projected air emission levels from the Unit B CCCT project will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka NWA.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the Unit B CCCT project. Visible emissions from the CTG/HRSG stack, the primary Unit B CCCT project emission source, will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the Unit B CTG/HRSG will be low due to the use of low-sulfur pipeline-quality natural gas and ULSD fuel oil. The Unit B CCCT project will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACT RESULTS

10.1 OVERVIEW

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

PSD Class I areas located within 300 km of the Unit B CCCT project include the Okefenokee NWA in Georgia and the Chassahowitzka NWA and Everglades National Park in Florida. The Stanton Energy Center is located 250 km (155 miles) south of the Okefenokee NWA and 288 km (179 miles) north of the Everglades National Park. The nearest PSD Class I area is the Chassahowitzka NWA, situated approximately 144 km (90 miles) to the northwest of the project site. Since the other two PSD Class I areas are located at much greater distances from Stanton, the Class I impact analysis was confined to the Chassahowitzka NWA.

10.2 CONCLUSIONS

Comprehensive dispersion modeling using the CALMET/CALPUFF/CALPOST modeling suite demonstrates that the Unit B CCCT project will have insignificant air quality impacts for all modeled PSD pollutants and all averaging periods. Accordingly, a multi-source cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2, SO_2, and PM_{10} was not required.

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

10.3 GENERAL APPROACH

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

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

10.4 MODEL SELECTION AND USE

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

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

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

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

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

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

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

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

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

10.4.1 CALMET

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

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

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

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

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

10.4.2 CALPUFF

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

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

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

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

- CALPUFF domain configured to include the Unit B CCCT project emission sources and all Class I receptors with a minimum 50-km buffer in all directions.
- 4-km spacing meteorological and computational grid.
- Class I receptors as defined by NPS.
- Modeling of 11 species (SO_2, sulfate, NO_x, nitric acid [HNO_3], nitrate, $PM_{1.0}$, $PM_{0.25}$, $PM_{0.20}$, $PM_{0.15}$, $PM_{0.10}$, and $PM_{0.05}$).
- Use of the MESOPUFF II chemical mechanism module.
- IWAQM default guidance, including Pasquill-Gifford dispersion coefficients.
- 2001 through 2003 ozone data from the Clean Air Status and Trends Network (CASTNet) and Atmospheric Infrared Sounder (AIRS) stations.
- Background ammonia concentration of 0.5 ppb.
- Integrated puff sampling methodology.
- No consideration of building downwash.

The PM fractions indicated previously address the PM size distribution expected for the Unit B CT/HRSG when firing ULSD fuel oil. The Class I impacts for the PM_{10} fractions, together with primary sulfate impacts, were summed to obtain total PM_{10} impacts.

10.4.3 POSTUTIL

POSTUTIL is a postprocessing program used to process the concentrations generated by CALPUFF. POSTUTIL was used to recompute the HNO_3/nitrate concentration partition, develop visibility PM component emission rates (i.e., elemental and organic carbon PM fractions), consolidate the PM_{10} impacts (i.e., impacts due to PM_{10} fractions and primary sulfate), consolidate the wet and dry nitrogen and sulfur fluxes, and convert sulfate and nitrate fluxes to total sulfur and total nitrogen fluxes.

10.4.4 CALPOST

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

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

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

10.5 RECEPTOR GRIDS

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

10.6 MODELED EMISSION SOURCES

Unit B CCCT project modeled emission sources included only the CTG/HRSG unit. The Unit B cooling tower emission source will have minor PM_{10} emission rates and a low release height. Accordingly, this emission source will have negligible impacts at the distant Chassahowitzka NWA Class I area.

Stack parameters and maximum NO_x and PM_{10} emission rates when firing ULSD fuel oil under operating Case 1 conditions (100-percent load and 20°F ambient temperature) were used for the Unit B CTG/HRSG. Conservatively, the higher maximum SO_2 and H_2SO_4 mist emission rates when firing natural gas was also used. Table 10-1 summarizes the Unit B CTG/HRSG emission source stack parameters and emission rates used in the CALPUFF modeling assessments.

10.7 MODEL RESULTS

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

10.7.1 PSD CLASS I SIGNIFICANT IMPACT LEVEL ANALYSIS

Table 10-2 summarizes Unit B CTG/HRSG NO_2, SO_2, and PM_{10} impacts with respect to the PSD Class I SILs. This table provides the highest annual average impacts (for NO_2, SO_2, and PM_{10}), highest 3-hour average impacts (for SO_2), and highest 24-hour average impacts (for SO_2 and PM_{10}).

All impacts are below the PSD Class I SILs for all pollutants and all averaging periods. Accordingly, a multisource cumulative assessment of air quality impacts with respect to the PSD Class I increments for NO_2, SO_2, and PM_{10} was not required.

10.7.2 SULFUR AND NITROGEN DEPOSITION

Table 10-3 summarizes the Unit B CTG/HRSG total wet and dry annual sulfur and nitrogen deposition rates. As shown, sulfur and nitrogen deposition impacts will be below the

Table 10-1. CALPUFF Modeling Data

Parameter	Units	Value
Stack height	ft	205
Stack diameter	ft	20.0
Stack velocity	ft/sec	66.1
Stack temperature	°F	262
SO_2 emissions	lb/hr	12.4
H_2SO_4 emissions	lb/hr	1.9
NO_x emissions	lb/hr	65.4
PM_{10} emissions (excluding H_2SO_4 mist)	lb/hr	34.6

Source: ECT, 2008.

Table 10-2. Summary of Class I Air Quality Impacts—NO_x, SO_2, and PM_{10}

Pollutant	Year of Meteorology	Averaging Period	Class I Area Impact Chassahowitzka NWA ($\mu g/m^3$)
NO_x	2001	Annual	0.00092
	2002		0.00092
	2003		0.00112
	Maximum		**0.00112**
PSD SIL			0.1
% of PSD SIL			1.1
Exceed PSD SIL			No
SO_2	2001	Annual	0.00032
	2002		0.00032
	2003		0.00036
	Maximum		**0.00036**
PSD SIL			0.1
% of PSD SIL			0.4
Exceed PSD SIL			No
SO_2	2001	24-Hour	0.0056
	2002		0.0067
	2003		0.0063
	Maximum		**0.0067**
PSD SIL			0.2
% of PSD SIL			3.4
Exceed PSD SIL			No
SO_2	2001	3-Hour	0.015
	2002		0.016
	2003		0.016
	Maximum		**0.016**
PSD SIL			1.0
% of PSD SIL			1.6
Exceed PSD SIL			No
PM_{10}	2001	Annual	0.0011
	2002		0.0011
	2003		0.0013
	Maximum		**0.0013**
PSD SIL			0.2
% of PSD SIL			0.6
Exceed PSD SIL			No
PM_{10}	2001	24-Hour	0.020
	2002		0.029
	2003		0.022
	Maximum		**0.029**
PSD SIL			0.3
% of PSD SIL			9.7
Exceed PSD SIL			No

Source: ECT, 2008.

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

Pollutant	Year of Meteorology	Averaging Period	Chassahowitzka NWA $\mu g/m^2/s$	Chassahowitzka NWA kg/ha/yr
Total wet and dry Nitrogen deposition	2001	Annual	0.0000019	0.00059
	2002		0.0000020	0.00063
	2003		0.0000022	0.00068
	Maximum		**0.0000022**	**0.00068**
FLM DAT				0.01
% of FLM DAT SIL				6.8
Exceed FLM DAT				No
Total wet and dry Sulfur deposition	2001	Annual	0.00000136	0.00043
	2002		0.00000138	0.00044
	2003		0.00000140	0.00044
	Maximum		**0.00000140**	**0.00044**
FLM DAT				0.01
% of FLM DAT SIL				4.4
Exceed FLM DAT				No

Note: $\mu g/m^2/s$ = microgram per square meter per second.

Source: ECT, 2008.

FLM sulfur and nitrogen deposition analysis threshold (DAT) of 0.01 kilogram per hectare per year (kg/ha/yr).

10.7.3 REGIONAL HAZE

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

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

Unit B CTG/HRSG maximum 24-hour regional haze impacts are summarized on Table 10-4. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (sulfate, NO_3, and particulate matter fine [PMF]) as well as the total emission source β_{ext}, background β_{ext} based on natural conditions as defined by the FLM, background visual range in units of km and deciview (dv), and the highest changes in β_{ext} and dv as calculated by the CALPOST program. The maximum change in β_{ext} is projected to be 1.9 percent, which is below the 5-percent FLM screening level value.

10.8 **SUMMARY**

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

Table 10-4. Chassahowitzka NWA Regional Haze Impacts

Maximum 24-Hour Average Impacts	Units	2001	2002	2003	Maximum
B_{ext-s} - SO_4	Mm^{-1}	0.059	0.078	0.039	0.078
B_{ext-s} - NO_3	Mm^{-1}	0.162	0.261	0.142	0.261
B_{ext-s} - Organic Carbon (OC)	Mm^{-1}	0.045	0.065	0.051	0.065
B_{ext-s} - Elemental Carbon (EC)	Mm^{-1}	0.033	0.048	0.038	0.048
B_{ext-s} - Soil (PMF)	Mm^{-1}	0.003	0.005	0.004	0.005
B_{ext-s} - Total	Mm^{-1}	0.302	0.457	0.274	0.457
B_{ext-b} - Background	Mm^{-1}	24.5	24.1	22.8	24.5
Visual Range, Background	km	159.6	162.3	171.4	171.4
Visual Range, Background	mi	99.1	100.8	106.5	106.5
Visual Range, Background	dv	9.0	8.8	8.3	9.0
Relative Humidity Factor - f(RH)	-	6.69	6.23	4.80	6.69
No. of Days with B_{ext} >5.0 %	-	0	0	0	0
No. of Days with B_{ext} >10.0 %	-	0	0	0	0
Largest B_{ext} change	%	1.23	1.90	1.20	1.90
NPS Significant Impact, Bext change	%	5.00	5.00	5.00	5.00
Exceed NPS Significant Impact	Y/N	N	N	N	Y
Percent of NPS Significant Impact	%	24.6	38.0	24.0	38.0
No. of Days with Delta Deciview >0.5 %	-	0	0	0	0
No. of Days with Delta Deciview >1.0 %	-	0	0	0	0
Largest Delta Deciview Change	-	0.122	0.188	0.119	0.188
Receptor LCC Easting (km)	km	1,410.8	1,409.1	1,410.0	N/A
Receptor LCC Northing (km)	km	-1,153.7	-1,153.9	-1,149.0	N/A
Distance From Unit B CTG/HRSG (km)	km	145.8	147.5	146.3	N/A
Direction From Unit B CTG/HRSG (Vect	Vector °	266	266	268	N/A

Source: ECT, 2008.

Table 10-5. Summary of Chassahowitzka NWA CALPUFF Model Results

A. Criteria Pollutants

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.0011	0.1
PM_{10}	Annual	0.0013	0.2
	24-hour	0.029	0.3
SO_2	Annual	0.00036	0.1
	24-hour	0.0067	0.2
	3-hour	0.016	1.0

B. Deposition

Pollutant	Averaging Time	Maximum Impact (kg/ha/yr)	Significant Impact (kg/ha/yr)
Nitrogen	Annual	0.00068	0.01
Sulfur	Annual	0.00044	0.01

C. Regional Haze

Pollutant	Averaging Time	Maximum Impact (% Change β_{ext})	Significant Impact (% Change β_{ext})
Regional haze	24-Hour	1.9	5.0

Source: ECT, 2008.

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APPENDIX A

EMISSION RATE CALCULATIONS

Appendix A - Stanton Unit B
Emission Rate Calculations - List of Tables

Source: ECT, 2008.

Table A-1. Stanton Unit B
Annual Emission Rate Summary

Pollutant	Potential Annual Emissions (tpy)			
	CT/HRSG[1]	ULSD Fuel Oil Storage Tank	Cooling Tower	Unit B Totals
Criteria Pollutants				
NO_x	79.6	N/A	N/A	79.6
CO	162.9	N/A	N/A	162.9
VOC	18.3	0.3	N/A	18.6
SO_2	54.4	N/A	N/A	54.4
PM_{10}	107.9	N/A	0.9	108.9
Pb	0.005	N/A	N/A	0.005
Hazardous Air Pollutants				
Formaldehyde	2.4	Neg.	N/A	2.4
Total HAP	4.9	Neg.	N/A	4.9
Other Pollutants				
H_2SO_4 Mist	8.3	N/A	N/A	8.3
PM	107.9	N/A	2.3	110.2
NH_3	65.1	N/A	N/A	65.1
Other Constituents				
CO_2	1,073,764	N/A	N/A	1,073,764

Neg. - negligible
N/A - not applicable

[1] Maximum of Annual Profiles 1, 2, and 3.

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

Table A-2. Stanton Unit B CT/HRSG Operating Cases

Case No.	Ambient Temperature (°F)	CT Inlet Air Temperature (°F)	Fuel Type		Load			Steam Augmentation	Evaporative Cooling	Duct Burner Firing[1]	Annual Profile #1 (hr/yr)	Annual Profile #2 (hr/yr)
			Nat. Gas	ULSD	100 %	75 %	50 %					
1 - NG	Winter 20	20	✓		✓							
2 - NG	20	20	✓			✓						
3 - NG	20	20	✓				✓					
4 - NG	Annual Average 70	66	✓		✓				✓		8,760	7,760
5 - NG	70	70	✓		✓							
6 - NG	70	70	✓			✓						
7 - NG	70	70	✓				✓					
8 - NG	Summer 95	79	✓		✓			✓	✓	✓		
9 - NG	95	79	✓		✓				✓	✓		
10 - NG	95	79	✓		✓				✓			
11 - NG	95	95	✓			✓						
12 - NG	95	95	✓				✓					
1 - ULSD	Winter 20	20		✓	✓							
2 - ULSD	20	20		✓		✓						
3 - ULSD	20	20		✓			✓					
4 - ULSD	Annual Average 70	66		✓	✓				✓			1,000
5 - ULSD	70	70		✓		✓						
6 - ULSD	70	70		✓			✓					
7 - ULSD	Summer 95	79		✓	✓				✓			
8 - ULSD	95	95		✓		✓						
9 - ULSD	95	95		✓			✓					

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[1] Duct burners are fired exclusively with natural gas.

Sources: ECT, 2008
OUC, 2008.

Table A-3. Stanton Unit B
CT/HRSG Hourly Criteria Pollutant, H_2SO_4 Mist, and NH_3 Emission Rates - Natural Gas

Amb. Temp. (°F)	Case No.	CT Load (%)	PM/PM$_{10}$[1] (lb/hr)	PM/PM$_{10}$[1] (g/sec)	SO$_2$[2] (lb/hr)	SO$_2$[2] (g/sec)	H$_2$SO$_4$[3] (lb/hr)	H$_2$SO$_4$[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1 - NG	100	19.9	2.51	10.7	1.35	1.64	0.207	0.00094	0.00012
	2 - NG	75	19.6	2.46	8.7	1.09	1.33	0.167	0.00076	0.00010
	3 - NG	50	19.2	2.42	6.9	0.87	1.06	0.134	0.00061	0.00008
70	4 - NG	100	19.8	2.49	9.8	1.24	1.51	0.190	0.00086	0.00011
	5 - NG	100	19.7	2.49	9.7	1.23	1.49	0.188	0.00085	0.00011
	6 - NG	75	19.4	2.45	8.0	1.01	1.22	0.154	0.00070	0.00009
	7 - NG	50	19.1	2.41	6.4	0.80	0.98	0.123	0.00056	0.00007
95	8 - NG	100	24.6	3.10	12.4	1.57	1.90	0.240	0.00109	0.00014
	9 - NG	100	24.0	3.03	11.7	1.48	1.79	0.226	0.00102	0.00013
	10 - NG	100	19.7	2.48	9.5	1.20	1.46	0.184	0.00083	0.00011
	11 - NG	75	19.4	2.44	7.5	0.95	1.15	0.145	0.00066	0.00008
	12 - NG	50	19.1	2.40	6.0	0.75	0.92	0.115	0.00052	0.00007
		Maximums	**24.6**	**3.10**	**12.4**	**1.57**	**1.90**	**0.240**	**0.00109**	**0.00014**

Temp. (°F)	Case No.	Load (%)	NO$_x$ (ppmvd)[5]	NO$_x$ (lb/hr)	NO$_x$ (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)[6]	VOC (g/sec)	NH$_3$ (ppmvd)[4]	NH$_3$ (lb/hr)	NH$_3$ (g/sec)
20	1 - NG	100	2.0	13.9	1.75	4.1	17.3	2.18	1.2	2.9	0.37	5.0	12.8	1.62
	2 - NG	75	2.0	11.1	1.40	4.1	13.9	1.75	1.2	2.3	0.29	5.0	10.3	1.29
	3 - NG	50	2.0	8.8	1.11	4.1	11.0	1.38	1.2	1.8	0.23	5.0	8.1	1.02
70	4 - NG	100	2.0	12.7	1.61	4.1	15.9	2.00	1.2	2.7	0.34	5.0	11.8	1.48
	5 - NG	100	2.0	12.6	1.59	4.1	15.7	1.98	1.2	2.6	0.33	5.0	11.7	1.47
	6 - NG	75	2.0	10.2	1.29	4.1	12.8	1.61	1.2	2.1	0.27	5.0	9.5	1.19
	7 - NG	50	2.0	8.1	1.02	4.1	10.1	1.27	1.2	1.7	0.21	5.0	7.5	0.94
95	8 - NG	100	2.0	16.1	2.03	7.6	37.2	4.69	1.5	4.2	0.53	5.0	14.9	1.87
	9 - NG	100	2.0	15.2	1.91	7.6	36.1	4.54	1.5	4.1	0.51	5.0	14.0	1.77
	10 - NG	100	2.0	12.3	1.55	4.1	15.4	1.94	1.2	2.6	0.33	5.0	11.4	1.44
	11 - NG	75	2.0	9.6	1.21	4.1	12.0	1.52	1.2	2.0	0.25	5.0	8.9	1.12
	12 - NG	50	2.0	7.6	0.96	4.1	9.5	1.20	1.2	1.6	0.20	5.0	7.0	0.89
		Maximums	**2.0**	**16.1**	**2.03**	**7.6**	**37.2**	**4.69**	**1.5**	**4.2**	**0.53**	**5.0**	**14.9**	**1.87**

[1] Filterable PM$_{10}$, as measured by EPA Reference Methods 201 or 201A.

[2] Natural gas sulfur content of 2.0 gr/100 scf.

[3] 10% conversion of SO$_2$ to H$_2$SO$_4$;

[4] Natural Gas Combustion, Table 1.4-2, AP-42, 3/98.

[5] Corrected to 15% O$_2$.

[6] Expressed as methane.

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

Table A-4. Stanton Unit B
CT/HRSG Hourly Criteria Pollutant, H_2SO_4 Mist, and NH_3 Emission Rates - ULSD Fuel Oil

Amb. Temp. (°F)	Case No.	CT Load (%)	PM/PM_{10}[1] (lb/hr)	(g/sec)	SO_2[2] (lb/hr)	(g/sec)	H_2SO_4[3] (lb/hr)	(g/sec)	Lead[4] (lb/hr)	(g/sec)
20	1 - ULSD	100	34.6	4.36	3.2	0.41	0.50	0.063	0.00162	0.00020
	2 - ULSD	75	34.5	4.34	2.6	0.33	0.40	0.050	0.00130	0.00016
	3 - ULSD	50	34.4	4.33	2.0	0.26	0.31	0.040	0.00102	0.00013
70	4 - ULSD	100	34.5	4.35	3.0	0.38	0.46	0.058	0.00150	0.00019
	5 - ULSD	75	34.4	4.34	2.4	0.30	0.37	0.047	0.00121	0.00015
	6 - ULSD	75	34.3	4.33	1.9	0.24	0.29	0.037	0.00095	0.00012
95	7 - ULSD	100	34.5	4.35	2.9	0.36	0.44	0.056	0.00144	0.00018
	8 - ULSD	75	34.4	4.34	2.3	0.29	0.35	0.044	0.00114	0.00014
	9 - ULSD	50	34.3	4.32	1.8	0.23	0.27	0.034	0.00089	0.00011
		Maximums	34.6	4.36	3.2	0.41	0.50	0.063	0.00162	0.00020

Temp. (°F)	Case No.	Load (%)	NO_x (ppmvd)[5]	(lb/hr)	(g/sec)	CO (ppmvd)[5]	(lb/hr)	(g/sec)	VOC (ppmvd)[5]	(lb/hr)[6]	(g/sec)	NH_3 (ppmvd)[4]	(lb/hr)	(g/sec)
20	1 - ULSD	100	8.0	65.4	8.24	8.0	39.8	5.01	2.8	8.0	1.01	5.0	15.1	1.90
	2 - ULSD	75	8.0	52.0	6.56	8.0	31.7	3.99	2.7	6.0	0.76	5.0	12.0	1.51
	3 - ULSD	50	8.0	40.5	5.10	8.0	24.7	3.11	2.8	5.0	0.63	5.0	9.4	1.18
70	4 - ULSD	100	8.0	60.3	7.59	8.0	36.7	4.62	2.8	7.5	0.94	5.0	13.9	1.75
	5 - ULSD	75	8.0	48.1	6.06	8.0	29.3	3.69	2.8	6.0	0.76	5.0	11.1	1.40
	6 - ULSD	75	8.0	37.5	4.73	8.0	22.8	2.88	2.9	5.0	0.63	5.0	8.7	1.09
95	7 - ULSD	100	8.0	58.1	7.32	8.0	35.4	4.46	2.8	7.0	0.88	5.0	13.4	1.69
	8 - ULSD	75	8.0	45.5	5.74	8.0	27.7	3.49	2.8	5.5	0.69	5.0	10.5	1.33
	9 - ULSD	50	8.0	35.4	4.46	8.0	21.5	2.71	3.0	4.5	0.57	5.0	8.2	1.03
		Maximums	8.0	65.4	8.24	8.0	39.8	5.01	3.0	8.0	1.01	5.0	15.1	1.90

[1] Filterable PM_{10}, as measured by EPA Reference Methods 201 or 201A.

[2] ULSD fuel oil sulfur content of 0.0015 weight percent S.

[3] 10% conversion of SO_2 to H_2SO_4;

[4] - Emission factors for Pb (7.73 x 10^{-6} lb/MMBtu) is higher of University of Iowa and Siemens Westinghouse data; see Table A-6..

[5] Corrected to 15% O_2.

[6] Expressed as methane.

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

Table A-5a. Stanton Unit B
CT Hazardous Air Pollutant Hourly Emission Rates - Natural Gas

Parameter	Units	Value											
Case	N/A	1-G	2-G	3-G	4-G	5-G	6-G	7-G	8-G	9-G	10-G	11-G	12-G
Maximum CT Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,922.1	1,555.0	1,242.1	1,763.9	1,745.8	1,431.7	1,142.6	1,788.0	1,709.2	1,709.2	1,348.4	1,073.6

Hazardous Air Pollutant	Emission Factors[1-3] (lb/10^6 Btu)	Hourly Emissions											
		1-G (lb/hr)	2-G (lb/hr)	3-G (lb/hr)	4-G (lb/hr)	5-G (lb/hr)	6-G (lb/hr)	7-G (lb/hr)	8-G (lb/hr)	9-G (lb/hr)	10-G (lb/hr)	11-G (lb/hr)	12-G (lb/hr)
1,3-Butadiene	4.30E-07	8.26E-04	6.69E-04	5.34E-04	7.58E-04	7.51E-04	6.16E-04	4.91E-04	7.69E-04	7.35E-04	7.35E-04	5.80E-04	4.62E-04
Acetaldehyde	4.00E-05	7.69E-02	6.22E-02	4.97E-02	7.06E-02	6.98E-02	5.73E-02	4.57E-02	7.15E-02	6.84E-02	6.84E-02	5.39E-02	4.29E-02
Acrolein	6.40E-06	1.23E-02	9.95E-03	7.95E-03	1.13E-02	1.12E-02	9.16E-03	7.31E-03	1.14E-02	1.09E-02	1.09E-02	8.63E-03	6.87E-03
Arsenic (As)	1.96E-07	3.77E-04	3.05E-04	2.44E-04	3.46E-04	3.42E-04	2.81E-04	2.24E-04	3.51E-04	3.35E-04	3.35E-04	2.64E-04	2.11E-04
Benzene	1.20E-05	2.31E-02	1.87E-02	1.49E-02	2.12E-02	2.09E-02	1.72E-02	1.37E-02	2.15E-02	2.05E-02	2.05E-02	1.62E-02	1.29E-02
Beryllium (Be)	1.18E-08	2.26E-05	1.83E-05	1.46E-05	2.08E-05	2.05E-05	1.68E-05	1.34E-05	2.10E-05	2.01E-05	2.01E-05	1.59E-05	1.26E-05
Cadmium (Cd)	1.08E-06	2.07E-03	1.68E-03	1.34E-03	1.90E-03	1.88E-03	1.54E-03	1.23E-03	1.93E-03	1.84E-03	1.84E-03	1.45E-03	1.16E-03
Chromium (Cr)	1.37E-06	2.64E-03	2.13E-03	1.70E-03	2.42E-03	2.40E-03	1.97E-03	1.57E-03	2.45E-03	2.35E-03	2.35E-03	1.85E-03	1.47E-03
Ethylbenzene	3.20E-05	6.15E-02	4.98E-02	3.97E-02	5.64E-02	5.59E-02	4.58E-02	3.66E-02	5.72E-02	5.47E-02	5.47E-02	4.31E-02	3.44E-02
Formaldehyde[4]	3.04E-04	5.84E-01	4.73E-01	3.78E-01	5.36E-01	5.31E-01	4.35E-01	3.47E-01	5.44E-01	5.20E-01	5.20E-01	4.10E-01	3.26E-01
Lead (Pb)	4.90E-07	9.42E-04	7.62E-04	6.09E-04	8.65E-04	8.56E-04	7.02E-04	5.60E-04	8.76E-04	8.38E-04	8.38E-04	6.61E-04	5.26E-04
Manganese (Mn)	3.73E-07	7.16E-04	5.79E-04	4.63E-04	6.57E-04	6.50E-04	5.33E-04	4.26E-04	6.66E-04	6.37E-04	6.37E-04	5.02E-04	4.00E-04
Mercury (Hg)	2.55E-07	4.90E-04	3.96E-04	3.17E-04	4.50E-04	4.45E-04	3.65E-04	2.91E-04	4.56E-04	4.36E-04	4.36E-04	3.44E-04	2.74E-04
Naphthalene	1.30E-06	2.50E-03	2.02E-03	1.61E-03	2.29E-03	2.27E-03	1.86E-03	1.49E-03	2.32E-03	2.22E-03	2.22E-03	1.75E-03	1.40E-03
Nickel (Ni)	2.06E-06	3.96E-03	3.20E-03	2.56E-03	3.63E-03	3.59E-03	2.95E-03	2.35E-03	3.68E-03	3.52E-03	3.52E-03	2.78E-03	2.21E-03
Polycyclic Aromatic Hydrocarbons	2.20E-06	4.23E-03	3.42E-03	2.73E-03	3.88E-03	3.84E-03	3.15E-03	2.51E-03	3.93E-03	3.76E-03	3.76E-03	2.97E-03	2.36E-03
Propylene Oxide	2.90E-05	5.57E-02	4.51E-02	3.60E-02	5.12E-02	5.06E-02	4.15E-02	3.31E-02	5.19E-02	4.96E-02	4.96E-02	3.91E-02	3.11E-02
Selenium (Se)	2.35E-08	4.52E-05	3.66E-05	2.92E-05	4.15E-05	4.11E-05	3.37E-05	2.69E-05	4.21E-05	4.02E-05	4.02E-05	3.17E-05	2.53E-05
Toluene	1.30E-04	2.50E-01	2.02E-01	1.61E-01	2.29E-01	2.27E-01	1.86E-01	1.49E-01	2.32E-01	2.22E-01	2.22E-01	1.75E-01	1.40E-01
Xylene	6.40E-05	1.23E-01	9.95E-02	7.95E-02	1.13E-01	1.12E-01	9.16E-02	7.31E-02	1.14E-01	1.09E-01	1.09E-01	8.63E-02	6.87E-02
Maximum Individual HAP		0.584	0.473	0.378	0.536	0.531	0.435	0.347	0.544	0.520	0.520	0.410	0.326
Total HAPs		1.206	0.975	0.779	1.106	1.095	0.898	0.717	1.121	1.072	1.072	0.846	0.673

[1] - Organic emission factors, EPA AP-42, Section 3.1 Stationary Gas Turbines, Table 3.1-3., April 2000.

[2] - Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.

[3] - Metallic emission factors, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-4., July 1998.

[4] - Average of EPA AP-42 test data for large, heavy duty CTs.

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

Table A-5b. Stanton Unit B HRSG DB Hazardous Air Pollutant Hourly Emission Rates - Natural Gas

Parameter	Units		
Case	N/A	8-G	9-G
Maximum DB Hourly Fuel Flow:	10^6 ft^3	0.430	0.382

Hazardous Air Pollutant	Emission Factors[1-3] (lb/10^6 ft^3)	8-G (lb/hr)	9-G (lb/hr)
1,3-Butadiene			
Acetaldehyde			
Acrolein			
Arsenic (As)	2.00E-04	8.60E-05	7.64E-05
Benzene	2.10E-03	9.03E-04	8.03E-04
Beryllium (Be)	1.20E-05	5.16E-06	4.59E-06
Cadmium (Cd)	1.10E-03	4.73E-04	4.20E-04
Chromium (Cr)	1.40E-03	6.02E-04	5.35E-04
Ethylbenzene			
Formaldehyde	7.50E-02	3.22E-02	2.87E-02
Lead (Pb)	5.00E-04	2.15E-04	1.91E-04
Manganese (Mn)	3.80E-04	1.63E-04	1.45E-04
Mercury (Hg)	2.60E-04	1.12E-04	9.94E-05
Naphthalene	6.10E-04	2.62E-04	2.33E-04
Nickel (Ni)	2.10E-03	9.03E-04	8.03E-04
Polycyclic Aromatic Hydrocarbons	8.82E-05	3.79E-05	3.37E-05
Propylene Oxide			
Selenium (Se)	2.40E-05	1.03E-05	9.17E-06
Toluene	3.40E-03	1.46E-03	1.30E-03
Xylene			
Maximum Individual HAP		0.032	0.029
Total HAPs		0.037	0.033

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[1] - Organic emission factors, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-3., July 1998.

[2] - Metallic emission factors except lead, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-4., July 1998.

[3] - Lead emission factor, EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2., July 1998.

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

Table A-6. Stanton Unit B
CT Hazardous Air Pollutant Hourly Emission Rates - ULSD Fuel Oil

Parameter			Units	Value								
Scenario			N/A	1-ULSD	2-ULSD	3-ULSD	4-ULSD	5-ULSD	6-ULSD	7-ULSD	8-ULSD	9-ULSD
Maximum CT Hourly Fuel Flow:			10^6 Btu/hr (HHV)	2,097.5	1,684.3	1,324.5	1,933.4	1,558.4	1,226.7	1,862.7	1,472.3	1,155.3

Hazardous Air Pollutant	No. 2 FO Metals Concentration[1] (ppbw)	No. 2 FO Metals Concentration[2] (ppbw)	Emission Factors[3, 4, 5] (lb/10^6 Btu)	Hourly Emissions 1-ULSD (lb/hr)	2-ULSD (lb/hr)	3-ULSD (lb/hr)	4-ULSD (lb/hr)	5-ULSD (lb/hr)	6-ULSD (lb/hr)	7-ULSD (lb/hr)	8-ULSD (lb/hr)	9-ULSD (lb/hr)
1,3-Butadiene			1.60E-05	3.36E-02	2.69E-02	2.12E-02	3.09E-02	2.49E-02	1.96E-02	2.98E-02	2.36E-02	1.85E-02
Acetaldehyde												
Acrolein												
Arsenic (As)	N/A	<DL	1.10E-05	2.31E-02	1.85E-02	1.46E-02	2.13E-02	1.71E-02	1.35E-02	2.05E-02	1.62E-02	1.27E-02
Benzene			5.50E-05	1.15E-01	9.26E-02	7.28E-02	1.06E-01	8.57E-02	6.75E-02	1.02E-01	8.10E-02	6.35E-02
Beryllium (Be)	N/A	N/A	3.10E-07	6.50E-04	5.22E-04	4.11E-04	5.99E-04	4.83E-04	3.80E-04	5.77E-04	4.56E-04	3.58E-04
Cadmium (Cd)	N/A	<DL	4.80E-06	1.01E-02	8.08E-03	6.36E-03	9.28E-03	7.48E-03	5.89E-03	8.94E-03	7.07E-03	5.55E-03
Chromium (Cr)	31.0	242.4	1.25E-05	2.62E-02	2.10E-02	1.66E-02	2.42E-02	1.95E-02	1.53E-02	2.33E-02	1.84E-02	1.44E-02
Ethylbenzene												
Formaldehyde			3.50E-05	7.34E-02	5.90E-02	4.64E-02	6.77E-02	5.45E-02	4.29E-02	6.52E-02	5.15E-02	4.04E-02
Lead (Pb)	5.3	15.0	7.73E-07	1.62E-03	1.30E-03	1.02E-03	1.50E-03	1.21E-03	9.49E-04	1.44E-03	1.14E-03	8.93E-04
Manganese (Mn)	1.9	5.5	2.84E-07	5.95E-04	4.78E-04	3.76E-04	5.48E-04	4.42E-04	3.48E-04	5.28E-04	4.17E-04	3.28E-04
Mercury (Hg)	<DL	N/A	1.20E-06	2.52E-03	2.02E-03	1.59E-03	2.32E-03	1.87E-03	1.47E-03	2.24E-03	1.77E-03	1.39E-03
Naphthalene			3.50E-05	7.34E-02	5.90E-02	4.64E-02	6.77E-02	5.45E-02	4.29E-02	6.52E-02	5.15E-02	4.04E-02
Nickel (Ni)	2.0	28.9	1.49E-06	3.12E-03	2.51E-03	1.97E-03	2.88E-03	2.32E-03	1.83E-03	2.78E-03	2.19E-03	1.72E-03
Polycyclic Aromatic Hydrocarbons			4.00E-05	8.39E-02	6.74E-02	5.30E-02	7.73E-02	6.23E-02	4.91E-02	7.45E-02	5.89E-02	4.62E-02
Propylene Oxide												
Selenium (Se)	1.9	<DL	9.79E-08	2.05E-04	1.65E-04	1.30E-04	1.89E-04	1.53E-04	1.20E-04	1.82E-04	1.44E-04	1.13E-04
Toluene												
Xylene												
Maximum Individual HAP				0.115	0.093	0.073	0.106	0.086	0.067	0.102	0.081	0.064
Total HAPs				0.448	0.360	0.283	0.413	0.333	0.262	0.398	0.314	0.247

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 emission factors, EPA AP-42, Stationary Gas Turbines, Table 3.1-4., April 2000.

[4] - Metallic emission factors for As, Be, Cd, and Hg; EPA AP-42, Stationary Gas Turbines, Table 3.1-5., April 2000.

[5] - Metallic emission factors for Cr, Pb, Mn, Ni, and Se; higher of University of Iowa and Siemens Westinghouse data.

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

Table A-7. Stanton Unit B
CT/HRSG Hazardous Air Pollutant Annual Emission Rates

Hazardous Air Pollutant	Annual Emissions Profile 1 (ton/yr)	Annual Emissions Profile 2 (ton/yr)	Annual Emissions Profile 3 (ton/yr)
1,3-Butadiene	0.003	0.018	0.003
Acetaldehyde	0.309	0.274	0.313
Acrolein	0.049	0.044	0.050
Arsenic	0.002	0.012	0.002
Benzene	0.093	0.135	0.094
Beryllium	0.00009	0.00038	0.00009
Cadmium	0.008	0.012	0.008
Chromium	0.011	0.021	0.011
Ethylbenzene	0.247	0.219	0.251
Formaldehyde	2.349	2.114	2.381
Lead	0.004	0.004	0.004
Manganese	0.003	0.003	0.003
Mercury	0.002	0.003	0.002
Naphthalene	0.010	0.043	0.010
Nickel	0.016	0.016	0.016
Polycyclic Aromatic Hydrocarbons	0.017	0.054	0.017
Propylene Oxide	0.224	0.198	0.227
Selenium	0.00018	0.00026	0.00018
Toluene	1.004	0.890	1.018
Xylene	0.494	0.438	0.501
Maximum Individual HAP	2.349	2.114	2.381
Total HAPs	4.846	4.499	4.912

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

Table A-8a. Stanton Unit B

CT/HRSG Annual Criteria Pollutant, H_2SO_4 Mist, and NH_3 Emission Rates - Profile 1

Case	Operating Hours (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)
4-G	8,760	19.8	86.6	9.8	43.1	1.5	6.6	0.0009	0.0038
4-ULSD	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0000	0.0000
Totals	**8,760**	**N/A**	**86.6**	**N/A**	**43.1**	**N/A**	**6.6**	**N/A**	**0.0038**

Case	Operating Hours (hrs/yr)	Emission Rates							
		NO_x		CO		VOC		NH_3	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4-G	8,760	12.7	55.8	15.9	69.6	2.7	11.7	11.8	51.6
4-ULSD	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Totals	**8,760**	**N/A**	**55.8**	**N/A**	**69.6**	**N/A**	**11.7**	**N/A**	**51.6**

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

Table A-8b. Stanton Unit B
CT/HRSG Annual Criteria Pollutant, H_2SO_4 Mist, and NH_3 Emission Rates - Profile 2

Case	Operating Hours (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)
4-G	7,760	19.8	76.7	9.8	38.2	1.5	5.8	0.0009	0.0033
4-ULSD	1,000	34.5	17.3	3.0	1.5	0.5	0.2	0.0015	0.0007
Totals	**8,760**	**N/A**	**94.0**	**N/A**	**39.6**	**N/A**	**6.1**	**N/A**	**0.0041**

Case	Operating Hours (hrs/yr)	Emission Rates							
		NO_x		CO		VOC		NH_3	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
4-G	7,760	12.7	49.4	15.9	61.7	2.7	10.3	11.8	45.7
4-ULSD	1,000	60.3	30.1	36.7	18.3	7.5	3.8	13.9	7.0
Totals	**8,760**	**N/A**	**79.6**	**N/A**	**80.0**	**N/A**	**14.1**	**N/A**	**52.6**

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

Table A-8c. Stanton Unit B
CT/HRSG Annual Criteria Pollutant, H_2SO_4 Mist, and NH_3 Emission Rates - Profile 3

Case	Operating Hours (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)
8-G	8,760	24.6	107.9	12.4	54.4	1.9	8.3	0.0011	0.0048
Totals	**8,760**	**N/A**	**107.9**	**N/A**	**54.4**	**N/A**	**8.3**	**N/A**	**0.0048**

Case	Operating Hours (hrs/yr)	Emission Rates							
		NO_x		CO		VOC		NH_3	
		(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
8-G	8,760	16.1	70.4	37.2	162.9	4.2	18.3	14.9	65.1
Totals	**8,760**	**N/A**	**70.4**	**N/A**	**162.9**	**N/A**	**18.3**	**N/A**	**65.1**

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

Table A-9. Stanton Unit B
CT/HRSG Exhaust Flow Rates - Natural Gas

A. Exhaust Composition

		Exhaust Gas Composition - Volume %											
	MW	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature				
	(lb/mole)	100	75	50	100	100	75	50	100	100	100	75	50
Component	Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG
Ar	39.944	0.90	0.90	0.89	0.88	0.88	0.88	0.88	0.82	0.86	0.86	0.89	0.88
N_2	28.013	75.01	74.96	75.06	73.67	73.79	73.80	73.93	69.20	73.01	73.01	73.47	73.64
O_2	31.999	12.73	12.59	12.86	12.39	12.43	12.45	12.83	11.25	12.22	12.22	12.49	12.98
CO_2	44.010	3.78	3.85	3.72	3.77	3.77	3.76	3.58	3.74	3.77	3.77	3.69	3.47
H_2O	18.015	7.58	7.71	7.47	9.29	9.13	9.12	8.78	14.99	10.14	10.14	9.47	9.03
	Totals	28.46	100.01	28.47	100.00	100.00	100.01	100.00	100.00	100.00	100.00	100.01	100.00
Exhaust MW (lb/mole)		28.47	28.47	28.48	28.29	28.30	28.31	28.32	27.66	28.19	28.19	28.26	28.29
Exhaust Flow (lb/sec)		1,073.1	843.9	690.8	980.3	971.9	790.8	656.9	985.2	951.8	947.5	756.4	636.9
Exhaust Temperature (°F)		227.4	213.8	202.9	224.4	223.7	212.0	202.6	212.1	216.1	224.7	211.5	203.2
(K)		381.7	374.1	368.1	380.0	379.6	373.1	367.9	373.2	375.4	380.2	372.9	368.3
Exhaust O_2 (Vol %, Dry)		13.77	13.64	13.90	13.66	13.68	13.70	14.06	13.23	13.60	13.60	13.80	14.27

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)											
	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature				
	100	75	50	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG
ACFM	1,131,061	872,013	702,056	1,035,672	1,025,120	819,756	671,014	1,045,225	996,572	1,004,855	784,648	652,058
Velocity (fps)	60.0	46.3	37.2	54.9	54.4	43.5	35.6	55.5	52.9	53.3	41.6	34.6
Velocity (m/s)	18.3	14.1	11.4	16.7	16.6	13.3	10.9	16.9	16.1	16.2	12.7	10.5
SCFM, Dry[1]	805,148	632,408	518,873	726,736	721,380	586,961	489,109	699,989	701,317	698,177	560,093	473,531
ACFM (15% O_2, Dry)	1,262,528	990,046	770,925	1,153,000	1,140,112	909,223	709,112	1,154,547	1,108,178	1,117,388	855,236	666,727
SCFM (15% O_2, Dry)	972,445	777,992	615,771	891,925	882,910	716,353	566,629	909,542	867,858	863,973	674,340	532,246

[1] At 68 °F.

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

Table A-10. Stanton Unit B
CT/HRSG Exhaust Flow Rates - ULSD Fuel Oil

A. Exhaust Composition

		Exhaust Gas Composition - Volume %								
	MW	20°F Ambient Temperature			70°F Ambient Temperature			95°F Ambient Temperature		
	(lb/mole)	100	75	50	100	75	50	100	75	50
Component	Case No.	1 - ULSD	2 - ULSD	3 - ULSD	4 - ULSD	5 - ULSD	6 - ULSD	7 - ULSD	8 - ULSD	9 - ULSD
Ar	39.944	0.86	0.85	0.87	0.85	0.84	0.85	0.85	0.86	0.86
N_2	28.013	71.55	71.62	72.22	70.49	70.86	71.56	70.05	70.69	71.48
O_2	31.999	11.23	10.97	11.45	10.90	10.96	11.58	10.80	11.04	11.81
CO_2	44.010	5.52	5.72	5.50	5.55	5.58	5.28	5.54	5.49	5.11
H_2O	18.015	10.85	10.84	9.97	12.22	11.76	10.73	12.77	11.93	10.74
	Totals	28.46	100.00	28.47	100.01	100.00	100.00	100.01	100.01	100.00
Exhaust MW (lb/mole)		28.36	28.38	28.46	28.22	28.27	28.35	28.16	28.24	28.33
Exhaust Flow (lb/sec)		1,120.6	862.2	699.7	1,021.7	812.8	671.9	985.0	780.8	654.4
Exhaust Temperature (°F)		262.3	247.6	234.5	256.5	244.0	234.4	253.4	241.0	232.1
(K)		401.1	392.9	385.7	397.9	390.9	385.6	396.2	389.3	384.3
Exhaust O_2 (Vol %, Dry)		12.60	12.30	12.72	12.42	12.42	12.97	12.38	12.54	13.23

B. Exhaust Flow Rates

	Flow Rates (ft³/min)								
	20°F Ambient Temperature			70°F Ambient Temperature			95°F Ambient Temperature		
	100	75	50	100	75	50	100	75	50
Case No.	1 - ULSD	2 - ULSD	3 - ULSD	4 - ULSD	5 - ULSD	6 - ULSD	7 - ULSD	8 - ULSD	9 - ULSD
ACFM	1,246,007	938,614	745,609	1,132,772	883,897	718,714	1,089,730	846,226	698,116
Velocity (fps)	66.1	49.8	39.6	60.1	46.9	38.1	57.8	44.9	37.0
Velocity (m/s)	20.1	15.2	12.1	18.3	14.3	11.6	17.6	13.7	11.3
SCFM, Dry[1]	814,195	626,149	511,727	734,730	586,549	489,175	705,437	562,868	476,682
ACFM (15% O_2, Dry)	1,563,285	1,219,314	930,908	1,429,601	1,120,925	862,144	1,372,518	1,056,582	809,973
SCFM (15% O_2, Dry)	1,145,843	912,297	709,655	1,056,342	842,973	657,329	1,018,573	797,987	619,605

[1] At 68 °F.

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

Table A-11. Stanton Unit B
CT/HRSG Fuel Flow Rates - Natural Gas

A. Natural Gas Fuel Flow Rates - CT

	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature				
CT Load (%)	100	75	50	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG
Heat Input - LHV (10^6 Btu/hr)	1,731.6	1,400.9	1,119.0	1,589.1	1,572.8	1,289.8	1,029.4	1,610.8	1,539.8	1,539.8	1,214.8	967.2
Heat Input - HHV (10^6 Btu/hr)	1,922.1	1,555.0	1,242.1	1,763.9	1,745.8	1,431.7	1,142.6	1,788.0	1,709.2	1,709.2	1,348.4	1,073.6
Fuel Rate (lb/hr)	82,745	66,942	53,472	75,935	75,156	61,633	49,190	76,972	73,580	73,580	58,049	46,218
Fuel Rate (lb/sec)	22.985	18.595	14.853	21.093	20.877	17.120	13.664	21.381	20.439	20.439	16.125	12.838
Fuel Rate (10^6 ft^3/hr)	1.875	1.517	1.212	1.721	1.703	1.397	1.115	1.744	1.667	1.667	1.315	1.047

B. Natural Gas Flow Rates - DB

	20°F Ambient Temperature			70°F Ambient Temperature				95°F Ambient Temperature				
CT Load (%)	100	75	50	100	100	75	50	100	100	100	75	50
Case No.	1 - NG	2 - NG	3 - NG	4 - NG	5 - NG	6 - NG	7 - NG	8 - NG	9 - NG	10 - NG	11 - NG	12 - NG
Heat Input - LHV (10^6 Btu/hr)								397.0	353.0			
Heat Input - HHV (10^6 Btu/hr)								440.7	391.8			
Fuel Rate (lb/hr)								18,971	16,868			
Fuel Rate (lb/sec)								5.270	4.686			
Fuel Rate (10^6 ft^3/hr)								0.430	0.382			

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

Table A-12. Stanton Unit B
CT/HRSG Fuel Flow Rates - ULSD Fuel Oil

	20°F Ambient Temperature			70°F Ambient Temperature			95°F Ambient Temperature		
CT Load (%)	100	75	50	100	75	50	100	75	50
Case No.	1 - ULSD	2 - ULSD	3 - ULSD	4 - ULSD	5 - ULSD	6 - ULSD	7 - ULSD	8 - ULSD	9 - ULSD
Heat Input - LHV (10^6 Btu/hr)	1,978.8	1,589.0	1,249.5	1,824.0	1,470.2	1,157.3	1,757.3	1,389.0	1,089.9
Heat Input - HHV (10^6 Btu/hr)	2,097.5	1,684.3	1,324.5	1,933.4	1,558.4	1,226.7	1,862.7	1,472.3	1,155.3
Fuel Rate (lb/hr)	108,131	86,831	68,279	99,672	80,339	63,240	96,027	75,902	59,557
Fuel Rate (lb/sec)	30.036	24.120	18.966	27.687	22.316	17.567	26.674	21.084	16.544
Fuel Rate (10^3 gal/hr)	15.273	12.264	9.644	14.078	11.347	8.932	13.563	10.721	8.412

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

POTENTIAL EMISSION INVENTORY WORKSHEET

Stanton Energy Center Unit B

Table A-13
Unit B-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM$_{10}$

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Mechanical Draft Cooling Tower
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	Unit B Cooling Tower

EMISSION ESTIMATION EQUATIONS

PM Emission (lb/hr) = Recirculating Water Flow Rate (gpm) x (Drift Loss Rate (%) / 100) x 8.345 lb/gal x (TDS (ppmw) /10^6) x 60 min/hr

PM Emission (ton/yr) = PM Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

PM$_{10}$ Emission (lb/hr) = PM Emissions (lb/hr) x PM$_0$/PM Fraction

PM$_{10}$ Emission (ton/yr) = PM$_0$ Emission (lb/hr) x Operating Period (hrs/yr) x (1 ton/ 2,000 lb)

Source: ECT, 2006.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	6	
Recirculating Water Flow Rate:	56,000	gal/min
Drift Loss Rate:	0.0005	%
Total Dissolved Solids (TDS):	3,757	ppmw
PM$_{10}$/PM Fraction:	0.408	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.09	0.38	0.53	2.31
PM$_{10}$	0.036	0.16	0.21	0.94

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	SCS, 2008.
Recirculating Water Flow Rate (gpm)	SCS, 2008.
Drift Loss Rate (%)	SCS, 2008.
Total Dissolved Solids (ppmw)	SCS, 2008.
PM$_{10}$/PM Fraction:	ECT, 2008.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Davis, ECT	Jan-08
Data Entered by:	T.Davis, ECT	Jan-08

Table A-14. Stanton Unit B
Cooling Tower PM/PM$_{10}$ Fractions

Procedure Citation:

AWMA Abstract No. 216, Session No. AM-1b, Orlando, 2001.
Calculating Realistic PM$_{10}$ Emissions from Cooling Towers

Cooling Tower Design Data:

Cooling Tower Recirculating Water Total Dissolved Solids:	3,757	ppmw
Cooling Tower PM$_{10}$ Density (assumed NaCl):	2.2	g/cm^3

Particle Size Distribution:

Droplet Diameter (µm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (µm)	Mass Fraction (%)
10	5.24E-16	5.24E-10	1.97E-12	8.94E-19	1.195	0.000
20	4.19E-15	4.19E-09	1.57E-11	7.15E-18	2.391	0.196
30	1.41E-14	1.41E-08	5.31E-11	2.41E-17	3.586	0.226
40	3.35E-14	3.35E-08	1.26E-10	5.72E-17	4.781	0.514
50	6.54E-14	6.54E-08	2.46E-10	1.12E-16	5.976	1.816
60	1.13E-13	1.13E-07	4.25E-10	1.93E-16	7.172	5.702
70	1.80E-13	1.80E-07	6.75E-10	3.07E-16	8.367	21.348
90	3.82E-13	3.82E-07	1.43E-09	6.52E-16	10.758	49.812
110	6.97E-13	6.97E-07	2.62E-09	1.19E-15	13.148	70.509
130	1.15E-12	1.15E-06	4.32E-09	1.96E-15	15.539	82.023
150	1.77E-12	1.77E-06	6.64E-09	3.02E-15	17.929	88.012
180	3.05E-12	3.05E-06	1.15E-08	5.21E-15	21.515	91.032
210	4.85E-12	4.85E-06	1.82E-08	8.28E-15	25.101	92.468
240	7.24E-12	7.24E-06	2.72E-08	1.24E-14	28.687	94.091
270	1.03E-11	1.03E-05	3.87E-08	1.76E-14	32.273	94.689
300	1.41E-11	1.41E-05	5.31E-08	2.41E-14	35.859	96.288
350	2.24E-11	2.24E-05	8.43E-08	3.83E-14	41.835	97.011
400	3.35E-11	3.35E-05	1.26E-07	5.72E-14	47.812	98.340
450	4.77E-11	4.77E-05	1.79E-07	8.15E-14	53.788	99.071
500	6.54E-11	6.54E-05	2.46E-07	1.12E-13	59.764	99.071
600	1.13E-10	1.13E-04	4.25E-07	1.93E-13	71.717	100.000

Linear Interpolation:

Droplet Diameter (µm)	Droplet Volume (m^3)	Droplet Mass (g)	Particle Mass (g)	Particle Volume (m^3)	Particle Diameter (µm)	Mass Fraction (%)
70	1.80E-13	1.80E-07	6.75E-10	3.07E-16	8.367	21.348
90	3.82E-13	3.82E-07	1.43E-09	6.52E-16	10.758	49.812
					10.000	**40.791**

Mass Fraction of Cooling Tower PM ≤ PM$_{10}$:	0.408

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

Table A-15. Stanton Unit B
ULSD Fuel Oil Storage Tank
Volatile Organic Compound (VOC) Emission Rates

A. ULSD Fuel Oil Throughput Rate

Unit B	15,272,761	gallons/yr

B. Storage Tank Data

Tank No.	Height (ft)	Diameter (ft)	Volume		Roof Type	Roof Slope (ft/ft)	Color		Breather Vent Settings (psig)	
			(ft^3)	(gal)			Shell	Roof	Vacuum	Pressure
New ULSD Fuel Oil	40	64	128,680	962,590	Cone	0.0625	White	White	-0.03	0.03

C. Storage Tank VOC Emissions[1]

Tank No.	Working Loss		Breathing Loss		Total Losses	
	(lb/yr)	(ton/yr)	(lb/yr)	(ton/yr)	(lb/yr)	(ton/yr)
New ULSD Fuel Oil	582.77	0.29	71.86	0.0359	654.6	0.33

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[1] Emissions estimated using EPA TANKS 4.0.9d program.

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

Table A-16. Stanton Unit B
CT/HRSG Stack Parameters - Natural Gas

Height Above Grade	205.1	ft
	62.5	m
Exit Diameter	20.0	ft
	6.10	m

Parameter	Operating Case	1-G	2-G	3-G	4-G	5-G	6-G
	Load (%)	100	75	50	100	100	75
	Ambient Temp. (°F)	20	20	20	70	70	70
	CT Inlet Temp. (°F)	20	20	20	66	70	70
Flow Rate	acfm	1,131,061	872,013	702,056	1,035,672	1,025,120	819,756
Exit Velocity	ft/sec	60.0	46.3	37.2	54.9	54.4	43.5
	m/sec	18.3	14.1	11.4	16.7	16.6	13.3
Exit Temperature	°F	227.4	213.8	202.9	224.4	223.7	212.0
	K	381.7	374.1	368.1	380.0	379.6	373.1

Parameter	Operating Case	7-G	8-G	9-G	10-G	11-G	12-G
	Load (%)	50	100	100	100	75	50
	Ambient Temp. (°F)	70	95	95	95	95	95
	CT Inlet Temp. (°F)	70	79	79	79	95	95
Flow Rate	acfm	671,014	1,045,225	996,572	1,004,855	784,648	652,058
Exit Velocity	ft/sec	35.6	55.5	52.9	53.3	41.6	34.6
	m/sec	10.9	16.9	16.1	16.2	12.7	10.5
Exit Temperature	°F	202.6	212.1	216.1	224.7	211.5	203.2
	K	367.9	373.2	375.4	380.2	372.9	368.3

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

Table A-17. Stanton Unit B
CT/HRSG Stack Parameters - ULSD Fuel Oil

Height Above Grade	205.1	ft
	62.5	m
Exit Diameter	20.0	ft
	6.10	m

Parameter	Operating Case	1-ULSD	2-ULSD	3-ULSD	4-ULSD	5-ULSD
	Load (%)	100	75	50	100	75
	Ambient Temp. (°F)	20	20	20	70	70
	CT Inlet Temp. (°F)	20	20	20	66	70
Flow Rate	acfm	1,246,007	938,614	745,609	1,132,772	883,897
Exit Velocity	ft/sec	66.1	49.8	39.6	60.1	46.9
	m/sec	20.1	15.2	12.1	18.3	14.3
Exit Temperature	°F	262.3	247.6	234.5	256.5	244.0
	K	401.1	392.9	385.7	397.9	390.9

Parameter	Operating Case	6-ULSD	7-ULSD	8-ULSD	9-ULSD
	Load (%)	50	100	75	50
	Ambient Temp. (°F)	70	95	95	95
	CT Inlet Temp. (°F)	70	79	95	95
Flow Rate	acfm	718,714	1,089,730	846,226	698,116
Exit Velocity	ft/sec	38.1	57.8	44.9	37.0
	m/sec	11.6	17.6	13.7	11.3
Exit Temperature	°F	234.4	253.4	241.0	232.1
	K	385.6	396.2	389.3	384.3

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

Table A-18. Stanton Unit B Cooling Tower Stack Parameters

Parameter	Units	Cooling Tower[1]
Height Above Grade	ft m	50 15.2
Exit Diameter	ft m	33.5 10.21
Stack Area	ft^2	881.4
Flow Rate	acfm	1,223,820
Exit Velocity	ft/sec m/sec	23.1 7.1
Exit Temperature	°F K	90.0 305.4

[1] Per cell.

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

APPENDIX B

APPLICATION FOR AIR PERMIT
TITLE V SOURCE

ECT
Environmental Consulting & Technology, Inc.

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for any air construction permit at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

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

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

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Orlando Utilities Commission (OUC)**
2. Site Name: **Curtis H. Stanton Energy Center**
3. Facility Identification Number: **0950137**
4. Facility Location...
   Street Address or Other Locator: **5100 South Alafaya Trail**
   City: **Orlando** County: **Orange** Zip Code: **32831**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Denise M. Stalls, Vice President Environmental Affairs**
2. Application Contact Mailing Address
   Organization/Firm: **Orlando Utilities Commission**
   Street Address: **P.O. Box 3193**
   City: **Orlando** State: **Florida** Zip Code: **32802**
3. Application Contact Telephone Numbers...
   Telephone: **(407) 737-4236** ext. Fax: **(407) 384-4020**
4. Application Contact Email Address: **dstalls@ouc.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 3/6/08	3. PSD Number (if applicable): 373A
2. Project Number(s): 020-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

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

Air Construction Permit

■ Air construction permit. **(Modification Request to Permit No. PSD-FL-373)**

☐ 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

This PSD air construction permit application constitutes a revision to a previously filed application that resulted in the issuance of PSD-FL-373 for the Unit B IGCC. This application is for a combined cycle combustion turbine (CCCT) power generation facility to be located at the existing Curtis H. Stanton Energy Center in Orlando, Orange County, Florida. A detailed description of the Unit B CCCT project is provided in Section 2.0.

Unit B is being licensed under the Florida Electrical Power Plant Siting Act (FEPPSA).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
030	Unit B Combined-Cycle Combustion Turbine	AC1A	N/A
031	Unit B Cooling Tower	AC1A	N/A

Application Processing Fee

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

Note: The Stanton Energy Center is a FPPSA certified site. Application processing fee has been submitted to the Siting Coordination Office (SCO) within the FDEP's Energy Office pursuant to the FEPPSA.

APPLICATION INFORMATION

Owner/Authorized Representative Statement

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

1. Owner/Authorized Representative Name:
   Denise M. Stalls, Vice President Environmental Affairs
2. Owner/Authorized Representative Mailing Address
   Organization/Firm: **Orlando Utilities Commission**
   Street Address: **P.O. Box 3193**
   City: **Orlando** State: **Florida** Zip Code: **32802**
3. Owner/Authorized Representative Telephone Numbers
   Telephone: **(407) 737-4236** ext. Fax: **(407) 384-4020**
4. Owner/Authorized Representative Email Address: **dstalls@ouc.com**
5. Owner/Authorized Representative Statement:

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

Denise M. Stalls
Signature

2/26/08
Date

APPLICATION INFORMATION

Application Responsible Official Certification **NOT APPLICABLE**

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

1. Application Responsible Official Name:

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

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

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

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

   ☐ The designated representative at an Acid Rain source.

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

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

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:

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

   Signature Date

Professional Engineer Certification

1. Professional Engineer Name: **Thomas W. Davis**
Registration Number: 36777

2. Professional Engineer Mailing Address
Organization/Firm: **Environmental Consulting & Technology, Inc.**
Street Address: **3701 Northwest 98th Street**
City: **Gainesville** State: **FL** Zip Code: **32606**

3. Professional Engineer Telephone Numbers...
Telephone: **(352) 332-6230** ext. **11351** Fax: **(352) 332-6722**

4. Professional Engineer Email Address: **tdavis@ectinc.com**

5. Professional Engineer Statement:

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

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

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

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

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

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

Signature

2/26/08
Date

(seal)

* Attach any exception to certification statement.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **483.6** North (km) **3,151.1**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **28/29/17** Longitude (DD/MM/SS) **81/10/03**	
3. Governmental Facility Code: **4**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Denise M. Stalls, Vice President Environmental Affairs**

2. Facility Contact Mailing Address
Organization/Firm: **Orlando Utilities Commission**
Street Address: **P.O. Box 3193**
City: **Orlando** State: **Florida** Zip Code: **32802**

3. Facility Contact Telephone Numbers:
Telephone: **(407) 737-4236** ext. Fax: **(407) 384-4020**

4. Facility Contact Email Address: **dstalls@ouc.com**

Facility Primary Responsible Official **NOT APPLICABLE**

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

1. Facility Primary Responsible Official Name:

2. Facility Primary Responsible Official Mailing Address...
Organization/Firm:
Street Address:
City: State: Zip Code:

3. Facility Primary Responsible Official Telephone Numbers...
Telephone: ( ) - ext. Fax: ( ) -

4. Facility Primary Responsible Official Email Address:

FACILITY 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 Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOx	**A**	**N**
CO	**A**	**N**
PM/PM10	**A**	**N**
SO2	**A**	**N**
VOC	**A**	**N**
HAPS	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps **NOT APPLICABLE**

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

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

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

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   ☒ Attached, Document ID: Fig. 2-1 ☐ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):
   ☒ Attached, Document ID: **Section 2.0**
3. Rule Applicability Analysis:
   ☒ Attached, Document ID: **Section 4.0**
4. List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.):
   ☐ Attached, Document ID: ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification:
   ☒ Attached, Document ID: Section 2.0 ☐ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.):
   ☒ Attached, Document ID: **Section 8.0** ☐ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.):
   ☒ Attached, Document ID: **Sections 7.0 & 10.0** ☐ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):
   ☒ Attached, Document ID: Section 9.0 ☐ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):
   ☒ Attached, Document ID: Section 9.0 ☐ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☐ Attached, Document ID:________ ☒ Not Applicable

Additional Requirements for FESOP Applications NOT APPLICABLE

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

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

Additional Requirements Comment

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:
Combined-cycle unit comprised of one "F" Class combustion turbine (CT) and one heat recovery steam generator (HRSG) equipped with duct burners (DBs). The CT may be fired with either pipeline natural gas or ULSD fuel oil. The HRSG DBs will be fired exclusively with pipeline natural gas.

3. Emissions Unit Identification Number: **030 (Unit B CT/HRSG)**

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

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating: **300 MW (nominal)**

11. Emissions Unit Comment:
Generator nameplate rating is the nominal generation capacity for the Unit B combined-cycle unit.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

Natural Gas

NO_x – Dry low-NO_x (DLN) combustion and SCR [025, 139]

ULSD Fuel Oil

NO_x – Wet Injection and SCR [028, 139]

2. Control Device or Method Code(s): **Natural Gas (025, 139), ULSD Fuel Oil (028, 139)**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **N/A**

2. Maximum Production Rate: **N/A**

3. Maximum Heat Input Rate: **1,922.1** million Btu/hr, **HHV**

4. Maximum Incineration Rate: **N/A** pounds/hr
tons/day

5. Requested Maximum Operating Schedule:
24 hours/day **7** days/week
52 weeks/year **8,760** hours/year

6. Operating Capacity/Schedule Comment:

Heat input for the Unit B CTG during natural gas-firing is 1,922.1 x 10^6 Btu/hr at 100% load and 20°F ambient temperature, HHV basis. For ULSD fuel oil-firing, heat input is 2,097.5 MMBtu/hr (HHV) at 20°F turbine inlet temperature and 100% load.

Heat input for the Unit B HRSG DBs is 440.7x 10^6 Btu/hr at 100% load and 95°F ambient temperature, HHV basis. The Unit B HRSG DBs will be fired exclusively with pipeline natural gas.

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: **Unit B CTG/HRSG**	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: **205** feet	7. Exit Diameter: **20.0** feet
8. Exit Temperature: **212** °F	9. Actual Volumetric Flow Rate: **1,045,225** 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: **17** East (km): **483.616** North (km): **3,150.955**	14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)

15. Emission Point Comment:

Exit temperature (Field 8) and volumetric flow rate (Field 9) for are natural gas Operating Case No. 8 – 100% load, 95°F ambient temperature with CTG steam augmentation and inlet air evaporative cooling, and HRSG duct burner firing.

EMISSIONS UNIT INFORMATION
Section [1] of [2]

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine and heat recovery steam generator duct burners fired with pipeline natural gas.**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **2.305**	5. Maximum Annual Rate: **20,191.8**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **<0.1**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **1,025 HHV**
10. Segment Comment:		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Combustion turbine fired with ULSD distillate fuel oil.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousands Gallons Used**	
4. Maximum Hourly Rate: **15.273**	5. Maximum Annual Rate: **15,273**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **137.3 (HHV)**
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
1 – NOX	**025, 028**	**139**	**EL**
2 – CO			**EL**
3 – VOC			**NS**
4 – SO2			**EL**
5 – SAM			**NS**
6 – PM/PM10			**EL**
Notes:	**025 – DLN Combustors** **028 – water or steam injection**	**139 - SCR**	**NS – no standard** **EL – emissions limited**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control: **99% - Natural Gas**
3. Potential Emissions: **65.4** lb/hour **79.6** 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: **SPC Data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential lb/hr for ULSD fuel oil at 20°F turbine inlet; tpy at 66°F turbine inlet with 7,760 hrs/yr natural gas and 1,000 hrs/year ULSD fuel oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.0 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **16.1** lb/hour **55.8** tons/year
5. Method of Compliance: **CEMS; Part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas; lb/hr at 79°F turbine inlet; tpy at 66°F turbine inlet for 8,760 hrs/yr.** **Also subject to less stringent NO_x standards of NSPS Subpart KKKK.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8.0 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **65.4** lb/hour **30.1** tons/year
5. Method of Compliance: **CEMS; Part 75; 24-hour block average; midnight to midnight**	
6. Allowable Emissions Comment (Description of Operating Method): **ULSD fuel oil; lb/hr at 20°F turbine inlet; tpy at 66°F turbine inlet for 1,000 hrs/yr.** **Also subject to less stringent NO_x standards of NSPS Subpart KKKK.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **39.8** lb/hour **162.9** 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: **SPC Data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential lb/hr for ULSD fuel oil at 20°F turbine inlet; tpy at 79°F turbine inlet with 8,760 hrs/yr natural gas with steam augmentation, evaporative cooling, and duct burner firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **4.1 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.3** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas; lb/hr at 20°F turbine inlet.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7.6 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **37.2** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas with duct burner firing; lb/hr at 79°F turbine inlet.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 3 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **8.0 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **39.8** lb/hour **N/A** tons/year
5. Method of Compliance: **EPA Reference Method 10**	
6. Allowable Emissions Comment (Description of Operating Method): **ULSD fuel oil; lb/hr at 20°F turbine inlet.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 4 of 4

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **6.0 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **N/A** lb/hour **162.9** tons/year
5. Method of Compliance: **CEMS; 12-month average**	
6. Allowable Emissions Comment (Description of Operating Method): **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions
Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **8.0** lb/hour **18.3** 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: **SPC Data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential lb/hr for ULSD fuel oil at 20°F turbine inlet; tpy at 79°F turbine inlet with 8,760 hrs/yr natural gas with steam augmentation, evaporative cooling, and duct burner firing oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of **N/A**

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

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **12.4** lb/hour **54.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): **N/A** to tons/year	
6. Emission Factor: Reference: **SPC Data**	7. Emissions Method Code: **2**
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: **N/A** ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Detailed emission calculations are provided in Appendix A.

11. Potential, Fugitive, and Actual Emissions Comment:

Potential lb/hr and tpy for natural gas at 79°F turbine inlet with steam augmentation, evaporative cooling, and duct burner firing for 8,760 hrs/yr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Fuel Specification; 2.0 gr S/100 ft^3**	4. Equivalent Allowable Emissions: **12.4** lb/hour **54.4** tons/year
5. Method of Compliance: **Fuel Sampling and Analysis per 40 CFR Part 75 (Acid Rain Program)**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas Firing: lb/hr and tpy at 79°F turbine inlet with steam augmentation, evaporative cooling, and duct burner firing for 8,760 hrs/yr.** **Also subject to less stringent SO_2 standards of NSPS Subpart KKKK.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Fuel Specification; 0.0015% weight % S**	4. Equivalent Allowable Emissions: **3.2** lb/hour **1.5** tons/year
5. Method of Compliance: **Fuel Sampling and Analysis per 40 CFR Part 75 (Acid Rain Program)**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil Firing: lb/hr at 20°F turbine inlet; tpy at 20°F turbine inlet and 1,000 hrs/yr.** **Also subject to equivalent SO_2 standards of NSPS Subpart KKKK.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **1.9** 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: **SPC Data**	7. Emissions Method Code: **2**
8.a. Baseline Actual Emissions (if required): N/A tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): N/A tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment: **Potential lb/hr and tpy for natural gas at 79°F turbine inlet with steam augmentation, evaporative cooling, and duct burner firing for 8,760 hrs/yr.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions of **N/A**

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

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions
Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM_{10}**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **34.6** lb/hour **107.9** 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: **SPC Data**	7. Emissions Method Code: **5**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Detailed emission calculations are provided in Appendix A.

11. Potential, Fugitive, and Actual Emissions Comment:

Potential lb/hr for ULSD fuel oil at 20°F turbine inlet; tpy for natural gas at 79°F turbine inlet for 8,760 hrs/yr with steam augmentation, evaporative cooling, and duct burner firing ULSD fuel oil.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **24.6** lb/hour **107.9** tons/year
5. Method of Compliance: **EPA Method 9; annually**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas; lb/hr at 20°F turbine inlet; tpy at 79°F turbine inlet for 8,760 hrs/yr with steam augmentation, evaporative cooling, and duct burner firing.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **34.6** lb/hour **17.3** tons/year
5. Method of Compliance: **EPA Method 9; annually** **(Not required during any federal fiscal year in which ULSD fuel oil is fired for less than 400 hrs/yr).**	
6. Allowable Emissions Comment (Description of Operating Method): **ULSD fuel oil; lb/hr at 20°F turbine inlet; tpy at 66°F turbine inlet for 1,000 hrs/yr.** **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20 %** Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment: **Rule 62-212.400(4)(c), F.A.C. (BACT)**	

Visible Emissions Limitation: Visible Emissions Limitation ___ of __

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

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 3

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

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **O_2**	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: **NO_x diluent CEM requirements of 40 CFR Part 75 (Acid Rain Program).** **Specific CEMS information will be provided to FDEP when available.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 3 of 3

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

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: Fig. 2-5 ☐ 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: SCA Section 3.3
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 ☐ Previously Submitted, Date ________
4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ________ ☐ Previously Submitted, Date ________
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: ________
   Test Date(s)/Pollutant(s) Tested: ________

   ☐ Previously Submitted, Date: ________
   Test Date(s)/Pollutant(s) Tested: ________

   ☐ To be Submitted, Date (if known): ________
   Test Date(s)/Pollutant(s) Tested: ________

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ________ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

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

2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☒ Attached, Document ID: **Section 6.0** ☐ Not Applicable

3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) **To be provided to FDEP when available.**
   ☐ 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

5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☐ Not Applicable

Additional Requirements Comment

EMISSIONS UNIT INFORMATION
Section [2] of [2]

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:

Unit B water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

3. Emissions Unit Identification Number: **031 (Unit B Cooling Tower)**

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

9. Package Unit:
Manufacturer: Model Number:

10. Generator Nameplate Rating:

11. Emissions Unit Comment:

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:

   Drift eliminators (015)

2. Control Device or Method Code(s): **015**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate: **56,000 gal/min**

2. Maximum Production Rate: **N/A**

3. Maximum Heat Input Rate: **N/A** million Btu/hr,

4. Maximum Incineration Rate: **N/A** pounds/hr
tons/day

5. Requested Maximum Operating Schedule:
24 hours/day **7** days/week
52 weeks/year **8,760** hours/year

6. Operating Capacity/Schedule Comment:

Field 1 maximum process rate is the cooling tower water recirculation rate.

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: **Cooling Tower**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Cooling tower consists of 6 cells.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
5. Discharge Type Code: **V**	6. Stack Height: **50** feet	7. Exit Diameter: **33.5** feet
8. Exit Temperature: **N/A** °F	9. Actual Volumetric Flow Rate: **N/A** 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): **N/A** North (km): **N/A**	14. Emission Point Latitude/Longitude **N/A** Latitude (DD/MM/SS) **N/A** Longitude (DD/MM/SS)	
15. Emission Point Comment: **Cooling tower consists of 6 cells with 6 individual exhaust fans. Stack height and diameter data provided in Fields 6 and 7 are for each cell. Exhaust volume and temperature will vary with ambient temperatures.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Cooling Tower – process cooling, mechanical draft**		
2. Source Classification Code (SCC): **3-85-001-01**	3. SCC Units: **Million gallons throughput**	
4. Maximum Hourly Rate: **3.36**	5. Maximum Annual Rate: **29,434**	6. Estimated Annual Activity Factor: **N/A**
7. Maximum % Sulfur: **N/A**	8. Maximum % Ash: **N/A**	9. Million Btu per SCC Unit: **N/A**
10. Segment Comment:		

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:		

EMISSIONS UNIT INFORMATION
Section [2] of [2]

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – PM	**015**		**NS**
2 – PM10	**015**		**NS**
Notes:	**015 – mist eliminators**		**NS – no standard**

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions
Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.53** lb/hour **2.3** 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: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0005-percent drift loss**	4. Equivalent Allowable Emissions: **0.53** lb/hour **2.3** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

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

(Optional for unregulated emissions units.)

Potential, Estimated Fugitive, and Baseline & Projected Actual Emissions

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

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control: **N/A**
3. Potential Emissions: **0.21** lb/hour **0.94** 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: **AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): **N/A** tons/year	8.b. Baseline 24-month Period: **N/A** From: To:
9.a. Projected Actual Emissions (if required): **N/A** tons/year	9.b. Projected Monitoring Period: **N/A** ☐ 5 years ☐ 10 years
10. Calculation of Emissions: **Detailed emission calculations are provided in Appendix A.**	
11. Potential, Fugitive, and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

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

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE (BACT)**	2. Future Effective Date of Allowable Emissions: **N/A**
3. Allowable Emissions and Units: **0.0005-percent drift loss**	4. Equivalent Allowable Emissions: **0.21** lb/hour **0.94** tons/year
5. Method of Compliance: **Cooling tower vendor design data**	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions of

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

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: 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 ___ of __

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other

3. Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

5. Visible Emissions Comment

H. CONTINUOUS MONITOR INFORMATION NOT APPLICABLE

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

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:	

Continuous Monitoring System: Continuous Monitor of

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

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ Attached, Document ID: **Fig. 2-5** ☐ 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: **SCA Section 3.3**

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

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
☒ 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)
☒ 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

EMISSIONS UNIT INFORMATION
Section [2] of [2]

Additional Requirements for Air Construction Permit Applications

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

2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☒ Attached, Document ID: **Section 6.0** ☐ Not Applicable

3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: __________ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications **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

5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:_
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID:__________ ☐ Previously Submitted, Date:__________
   ☐ Not Applicable

EMISSIONS UNIT INFORMATION
Section [2] of [2]

Additional Requirements Comment

APPENDIX C

DISPERSION MODELING FILES

Stanton Unit B
Class I Area Dispersion Modeling Files

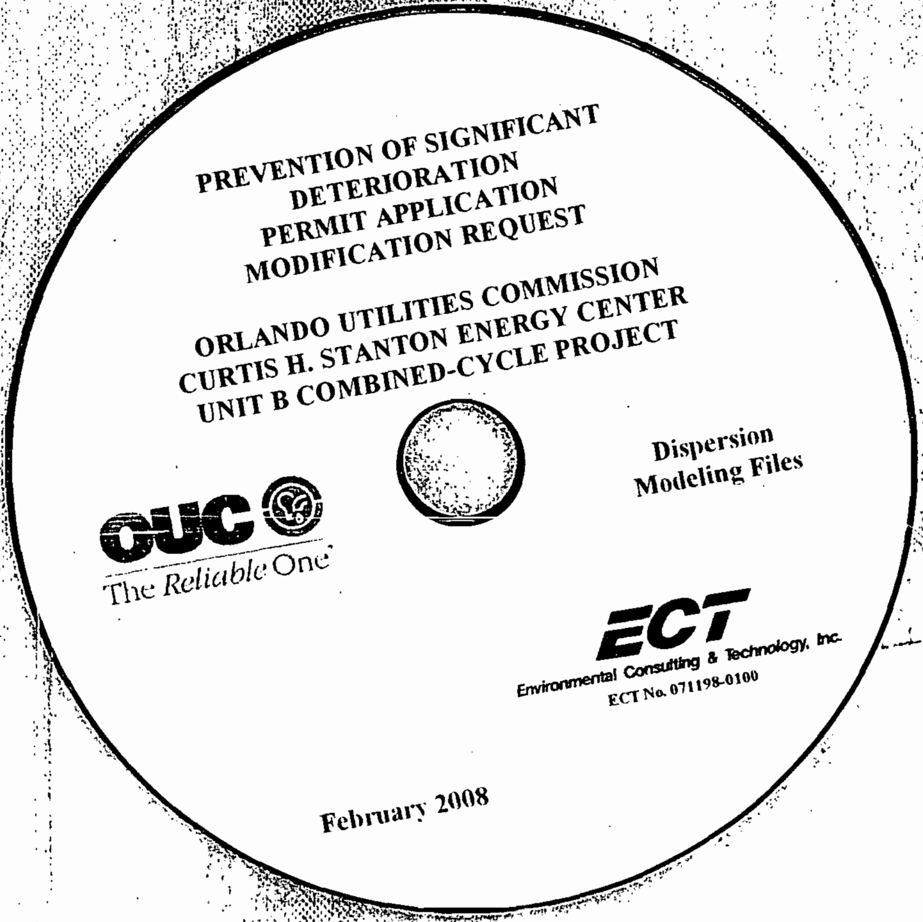
Directory Name	No. of Files	File Name	File Description
CLASS I/PUFF-INP	3	UBYY.INP	CALPUFF input files
		YY = 01, 02, and 03	
CLASS I/PUFF-OUT	3	UBYY.CON	CALPUFF output concentration files
	3	UBDFYY.CON	CALPUFF output concentration files, dry deposition flux files
	3	UBWFYY.CON	CALPUFF output concentration files, wet deposition flux files
	3	UBYY.LST	CALPUFF output concentration list files
	3	VISYY.ZIP	CALPUFF output visibility relative humidity (RH) files
		YY = 01, 02, and 03	
Subtotal Files	15		
CLASS I/UTIL-INP	3	UBYYP1.INP	POSTUTIL input files, NO_3/HNO_3 Repartition
	3	UBYYP2.INP	POSTUTIL input files, PM_{10} and Visibility Species Processing
	3	UBYYP3.INP	POSTUTIL input files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	9		
CLASS I/UTIL-OUT	3	UBYYP1.CON	POSTUTIL output concentration files, NO_3/HNO_3 Repartition
	3	UBYYP2.CON	POSTUTIL output concentration files, PM_{10} and Visibility Species Processing
	3	UBYYTDEP.CON	POSTUTIL output concentration files, Nitrogen and Sulfur Deposition
	3	UBYYP1.LST	POSTUTIL output list files, NO_3/HNO_3 Repartition
	3	UBYYP2.LST	POSTUTIL output list files, PM_{10} and Visibility Species Processing
	3	UBYYTDEP.LST	POSTUTIL output list files, Nitrogen and Sulfur Deposition
		YY = 01, 02, and 03	
Subtotal Files	18		
CLASS I/POST-INP	3	UBNO2CHYY.INP	CALPOST input NO_2 files - Chassahowitzka NWA
	3	UBPMCHYY.INP	CALPOST input PM_{10} files - - Chassahowitzka NWA
	3	UBSO2CHYY.INP	CALPOST input SO_2 files - - Chassahowitzka NWA
	3	UBNDCHYY.INP	CALPOST input nitrogen deposition files - Chassahowitzka NWA
	3	UBSDCHYY.INP	CALPOST input sulfur deposition files - Chassahowitzka NWA
	3	UBV1CHYY.INP	CALPOST input visibility files; Method 2 - Chassahowitzka NWA
		YY = 01, 02, and 03	
Subtotal Files	18		
CLASS I/POST-OUT	3	UBNO2CHYY.OUT	CALPOST output NO_2 files - Chassahowitzka NWA
	3	UBPMCHYY.OUT	CALPOST output PM_{10} files - - Chassahowitzka NWA
	3	UBSO2CHYY.OUT	CALPOST output SO_2 files - - Chassahowitzka NWA
	3	UBNDCHYY.OUT	CALPOST output nitrogen deposition files - Chassahowitzka NWA
	3	UBSDCHYY.OUT	CALPOST output sulfur deposition files - Chassahowitzka NWA
	3	UBV1CHYY.OUT	CALPOST output visibility files; Method 2 - Chassahowitzka NWA
		YY = 01, 02, and 03	
Subtotal Files	18		
Total Files	81		

Source: ECT, 2008.

Stanton Unit B
Class II Area Dispersion Modeling Files

Directory Name	No. of Files	File Name	File Description
CLASS II/AERMET DATA	5	MCOTPAYY.PFL	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Upper Air profile files
	5	MCOTPAYY.SFC	Meteorological Data - Orlando Intl. Airport Surface and Tampa Intl. Airport Upper Air surface files
		YY = 99 - 03	
Subtotal Files	10		
CLASS II/GEP	1	UB08.BPI	Building Profile Input Program (BPIP) input file
	1	UB08.PRO	Building Profile Input Program (BPIP) output file
	1	UB08.SUP	Building Profile Input Program (BPIP) output file
Subtotal Files	3		
CLASS II/AERMOD INPUT	5	UBYY.INP	AERMOD input files; nominal 1.0 g/s ermission rate
	5	UBPMYY.INP	AERMOD input files; PM_{10}
		YY = 99 - 03	
Subtotal files	10		
CLASS II/AERMOD OUTPUT	5	UBYY.INP	AERMOD output files; nominal 1.0 g/s emission rate
	5	UBPMYY.INP	AERMOD output files; PM_{10}
		YY = 99 - 03	
Subtotal files	10		
Total Files	33		

Source: ECT, 2008.



PREVENTION OF SIGNIFICANT
DETERIORATION
PERMIT APPLICATION
MODIFICATION REQUEST

ORLANDO UTILITIES COMMISSION
CURTIS H. STANTON ENERGY CENTER
UNIT B COMBINED-CYCLE PROJECT

Dispersion
Modeling Files

OUC
The Reliable One

ECT
Environmental Consulting & Technology, Inc.
ECT No. 071198-0100

February 2008