CALPINE
BLUE HERON
ENERGY CENTER

Site Certification Application

Volume 3
Chapter 10
Appendix 10.1.1

Submitted by

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FEDERAL AND STATE PERMIT APPLICATIONS OR APPROVALS

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APPENDIX 10.1.1

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION

PREVENTION OF SIGNIFICANT DETERIORATION

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

Calpine Construction Finance Company, L.P. (Calpine) is planning to construct and operate a new electric power generating plant in Indian River County, Florida. The new power plant, designated as the Blue Heron Energy Center (BHEC), will be a natural gas-fired combustion turbine generator (CTG)-based combined cycle (CC) facility with a nominal generating capacity of 1,080 megawatts (MW). The BHEC is being licensed under the Florida Electrical Power Plant Siting Act.

Operation of the proposed project will result in the emission of air contaminants. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes Calpine's application for authorization to commence construction in accordance with the Florida Department of Environmental Protection (FDEP) permitting rules contained in Chapter 62-212, F.A.C.

BHEC will be located in an attainment area and will have potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). Consequently, BHEC qualifies as a new major facility and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Rule 62-212.400, F.A.C. Therefore, this report and application is also submitted to satisfy the permitting requirements contained in the FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and a summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.

- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (dispersion modeling methodology) and 7.0 (dispersion modeling results) address ambient air quality impacts.
- Section 8.0 discusses current ambient air quality in the BHEC vicinity and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.

Attachments A through D provide the FDEP Application for Air Permit—Title V Source, CTG vendor information, emission rate calculations, and control technology vendor data, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in diskette format in Attachment E.

2.1 SUMMARY

BHEC will consist of four nominal 170-MW Siemens Westinghouse 501F CTGs, four heat recovery steam generators (HRSGs) equipped with supplemental duct burners (DBs), and two nominal 200-MW steam turbine generators (STGs); i.e., two "2 by 2 by 1" configurations. The CTGs will include provisions for inlet air evaporative cooling and steam power augmentation. BHEC will have a total nominal generation capacity of 1,080 MW. Ancillary equipment includes two main (north and south nine-cell towers) and one wastewater (three-cell tower) mechanical draft cooling towers, one emergency electric generator diesel engine, one emergency fire water pump diesel engine, and water treatment and storage facilities. The CTGs and DBs will be fired exclusively with pipeline-quality natural gas containing no more than 1.5 grains of total sulfur per one hundred dry standard cubic feet (gr S/100 dscf).

The planned BHEC construction start date is as soon as possible, but no later than January 2002. The projected date for the BHEC facility to begin commercial operation is March 2004, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, BHEC will have the potential to emit 453.2 tpy of nitrogen oxides (NO_x), 1,839.8 tpy of carbon monoxide (CO), 452.8 tpy of particulate matter (PM), 408.5 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM_{10}), 145.1 tpy of sulfur dioxide (SO_2), 140.6 tpy of volatile organic compounds (VOCs), and 0.5 tpy of lead. Regarding noncriteria pollutants, BHEC will potentially emit 26.6 tpy of sulfuric acid (H_2SO_4) mist and 0.0013 tpy of mercury. Based on these annual emission rate potentials, NO_x, CO, VOC, PM/PM_{10}, SO_2, and H_2SO_4 mist emissions are subject to PSD review.

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

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. The CTGs and DBs will utilize the latest burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates, and will be fired exclusively with pipeline-quality natural gas.
- Dry low-NO_x (DLN) combustors (for the CTGs) and low-NO_x burners (for the HRSG DBs), followed by selective catalytic reduction (SCR) is proposed as BACT for NO_x for the BHEC CTG/HRSG units. For all operating scenarios, CTG/HRSG NO_x exhaust concentrations will not exceed 3.5 parts per million by volume, dry (ppmvd), corrected to 15 percent oxygen (O_2). This concentration is consistent with recent FDEP BACT determinations for natural gas-fired CTGs. Average and incremental cost effectiveness of $SCONO_x$™ were determined to be \$9,982 and \$113,012, respectively. Since these costs exceed values previously determined by FDEP to be cost effective, installation of $SCONO_x$™ control technology is considered to be economically unreasonable. An additional NO_x BACT consideration pertinent to BHEC is the exclusive use of natural gas. CTG facilities using distillate fuel oil as a secondary fuel source will have higher NO_x emissions compared to facilities, such as BHEC, which will use natural gas as the only fuel source.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs for the CTGs and DBs. At

baseload operation, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 10.0 and 1.2 ppmvd at 15 percent O_2, respectively. At baseload operation with DB firing, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 15.6 and 3.4 ppmvd at 15 percent O_2, respectively. At baseload operation with DB firing and with steam power augmentation, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 38.5 and 6.6 ppmvd at 15 percent O_2, respectively; this operating mode will be limited to no more than 1,500 hours per year (hr/yr). At low load operation (i.e., between 60- and 70-percent load), the CTG/HRSG CO and VOC exhaust concentrations are projected to be 50.0 and 3.0 ppmvd at 15 percent O_2; this operating mode will be limited to no more than 2,880 hr/yr. These concentrations are consistent with prior FDEP BACT determinations for CTG/HRSG units (e.g., City of Tallahassee Purdom Unit 8, Lakeland Utilities McIntosh Unit 5, and Santa Rose Energy). Cost effectiveness of a CO oxidation catalyst control system was determined to be $1,553 per ton of CO. Installation of a CO oxidation catalyst control system is considered to be economically unreasonable.

- BACT for SO_2 and H_2SO_4 mist will be achieved through the exclusive use of low-sulfur, pipeline-quality natural gas.
- BHEC is projected to emit NO_x, CO, VOCs, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants, with the exception of PM_{10} and VOCs. The BHEC project will have potential VOC emissions in excess of 100 tpy and therefore exceeds the PSD *de minimis* monitoring significance level for ozone. Accordingly, BHEC qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants except PM_{10} and ozone. Representative, current quality-assured ambient PM_{10} and ozone data collected by FDEP at a monitoring site located in Fort Pierce, St. Lucie County, was used to satisfy the PSD preconstruction ambient air monitoring requirements for PM_{10} and ozone.

- With the exception of PM_{10}, 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 62-210.259(259), F.A.C. Accordingly, a multi-source interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class II increment consumption was required for PM_{10} only.
- Based on refined dispersion modeling, BHEC will not cause nor contribute to a violation of any NAAQS, Florida ambient air quality standards (AAQS), or PSD increment for Class I or Class II areas.
- Modeling of H_2SO_4 mist emissions shows that maximum project impacts will be well below FDEP's draft ambient reference concentrations.
- The ambient impact analysis also demonstrates that project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Everglades National Park) is located approximately 205 kilometers (km) south of the BHEC site. The Chassahowitzka National Wildlife Refuge Class I area is situated approximately 240 km to the northwest of the BHEC site. Air quality and visibility impacts on these Class I areas will be negligible.
- Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG cold start-up and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested for the BHEC CTGs: (a) up to 4 hours per start-up during cold start-up to CC operation, and (b) up to 3 hours per shutdown during shutdowns from CC operation. Cold start-up is defined as a startup to CC operation following a complete shutdown lasting at least 48 hours. CTG start-up is defined as that period of time from initiation of CTG firing unit until the unit reaches steady-state load operation. Steady-state operation is reached when the CTG reaches minimum load (i.e., 60 percent load) and the STG is declared available for load changes.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The BHEC will be located in Indian River County approximately 8 km (5 miles) southwest of the western city limits of Vero Beach. The 50.5-acre plant site is located approximately 9 km (5.5 miles) south-southeast of the intersection of State Road (SR) 60 and Interstate 95 (I-95). The plant site is bordered on the west by I-95, several borrow pit lakes, and undeveloped property; to the north by a single-family residence and the Indian River County correctional institute and solid waste landfill; to the east by a wastewater sprayfield operated by Ocean Spray Cranberries, Inc., and by inactive citrus groves; and to the south by undeveloped lands and I-95. The Spanish Lakes residential development is located southeast of the plant site in St. Lucie County. BHEC site location and vicinity maps are provided in Figures 2-1 and 2-2, respectively.

Major components of the BHEC include:

1. The base CC generating plant consisting of two CC configurations. Each CC configuration will consist of two F-class CTG/HRSG units and one STG for a total of four F-Class CTG/HRSG units and two STGs. Each CC configuration is commonly referred to as a "2 by 2 by 1" configuration with the values referring to the number of CTGs, HRSGs, and STGs, respectively.
2. Two 9-cell mechanical draft cooling towers.
3. One wastewater mechanical draft cooling tower.
4. One 1,400-kilowatt (kW) emergency diesel-fired electrical generator.
5. One emergency diesel-fired fire water pump.
6. Ancillary equipment, including raw and demineralized water storage tanks.

The CTGs will be Siemens Westinghouse 501F units. Each CTG will have provisions for inlet air evaporative cooling and steam power augmentation. Each CTG will be capable of producing a nominal 170 MW of electricity at International Standards Organization (ISO) conditions of 59 degrees Fahrenheit (°F) ambient air temperature. The HRSGs, which will be equipped with supplemental DBs, will furnish steam to the two STGs for

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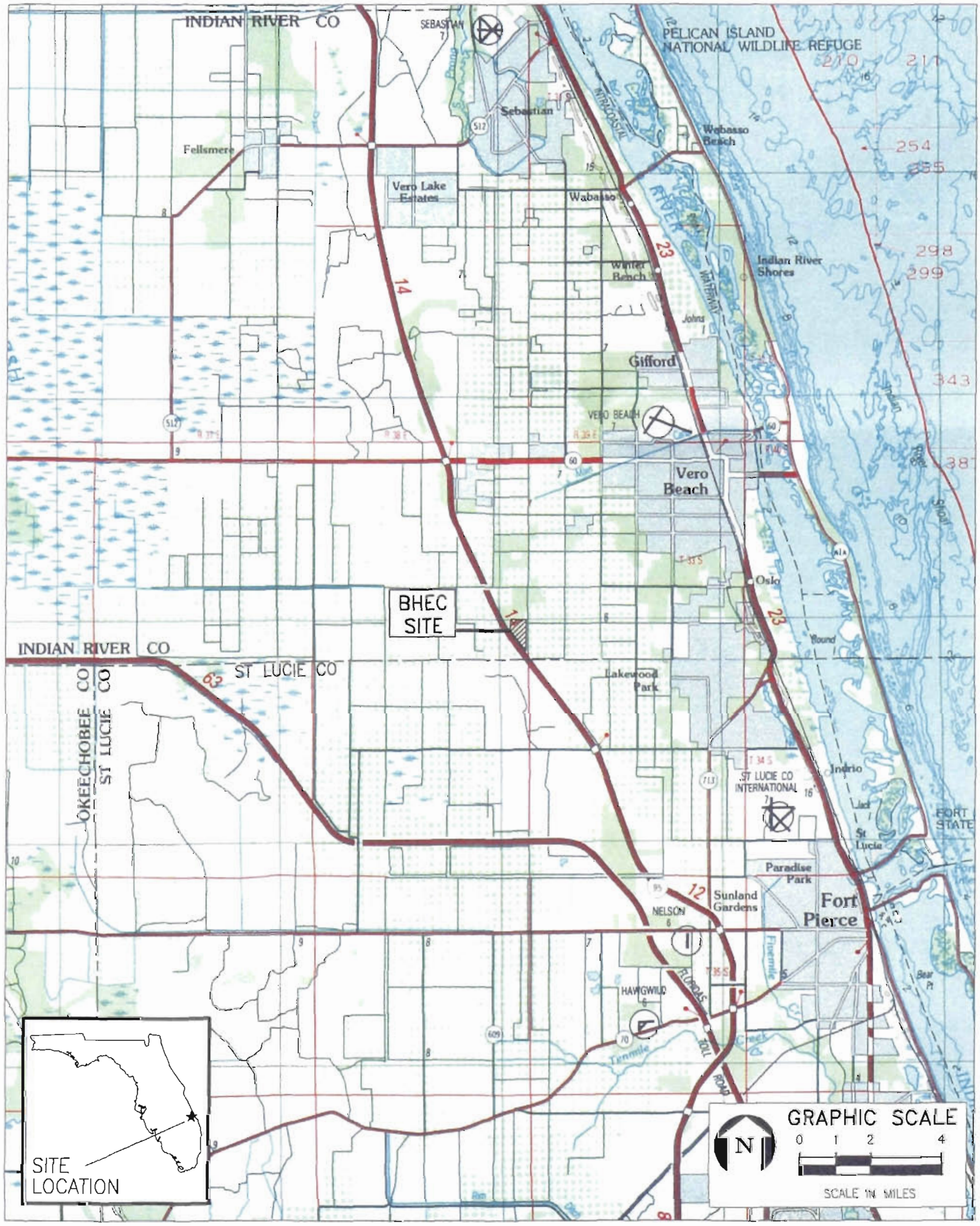

FIGURE 2-1.

BHEC SITE LOCATION MAP

Sources: USGS Quad: Ft. Pierce, FL, 1988; ECT, 2000.

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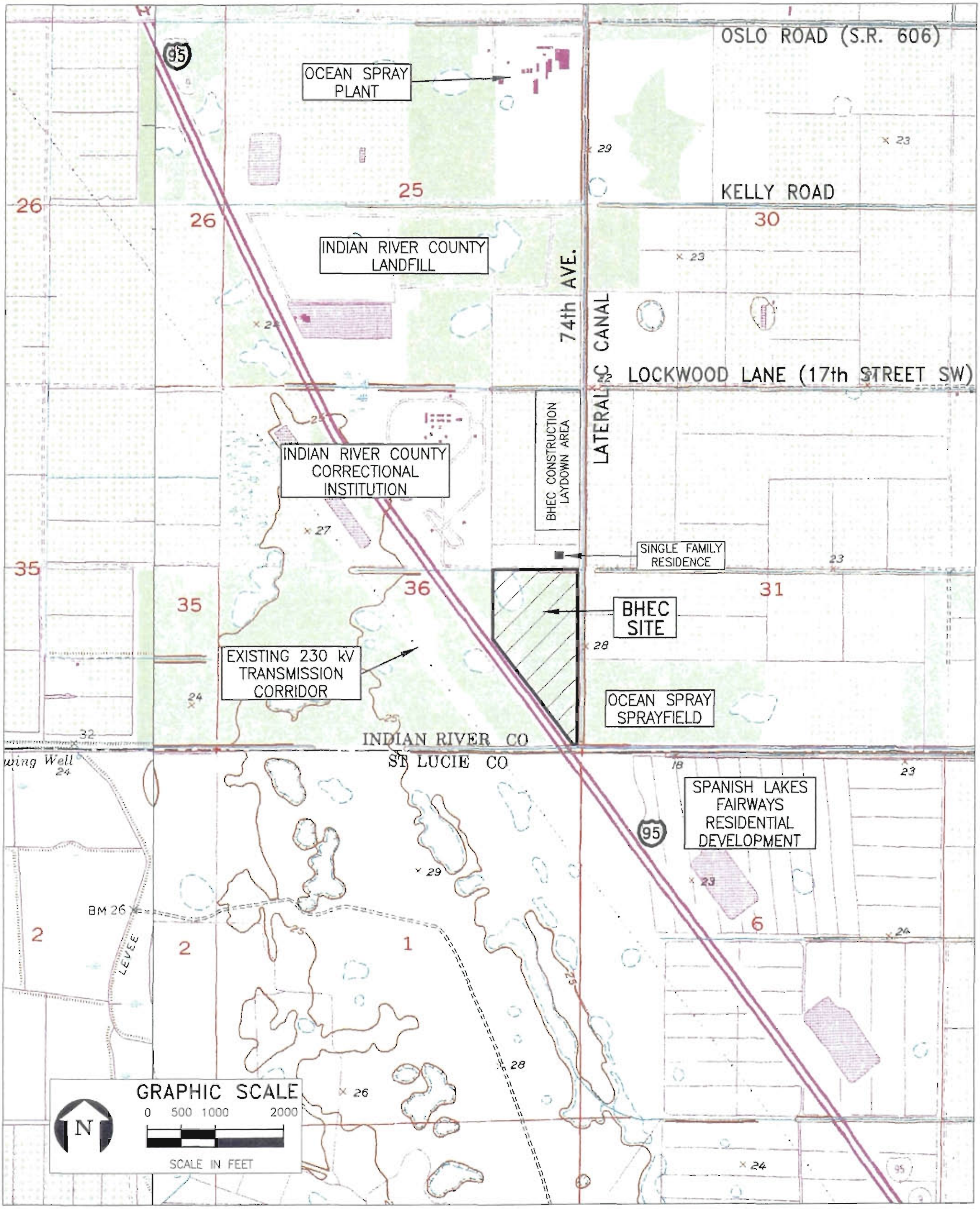

FIGURE 2-2.

SITE VICINITY MAP

Sources: USGS Quads: Oslo and East of Glum Slough, FL, 1983; ECT, 2000.

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the additional generation of electricity. The two STGs will each be capable of generating an additional nominal 200 MW of power for an overall facility nominal generation capacity of 1,080 MW. The CTGs and DBs will be fired exclusively with pipeline-quality natural gas.

The BHEC CTG/HRSG units will be capable of continuous operation at baseload for up to 8,760 hr/yr. The CTGs will normally operate between 60- and 100-percent load, with commensurate STG load. None of the CTGs will be designed to operate in simple cycle mode (i.e., bypassing the HRSG).

Combustion of natural gas in the CTGs and DBs will result in emissions of particulate matter (PM/PM_{10}), SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Cooling tower operations will result in PM/PM_{10} emissions due to drift losses.

Emission control systems proposed for the CTG/HRSG units include the use of DLN combustors (for the CTGs) and low-NO_x burners (for the DBs), followed by post-combustion SCR technology for control of NO_x; good combustion practices for abatement of CO and VOCs; and exclusive use of clean, low-sulfur, low-ash natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Drift eliminators will be utilized to control PM/PM_{10} emissions from the mechanical draft cooling towers.

A general site layout of the BHEC showing facility property lines, major process equipment and structures, and all emission points is presented in Figure 2-3. Access to the plant site will be provided by 74th Avenue (Range Line Road) which terminates at the Site. The plant entrance will have security gates to control site access. The entire Site perimeter will be fenced at the property boundary.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed BHEC natural gas-fired CC facility will include four nominal 170-MW CTGs, four HRSGs with supplemental DBs, and two nominal 200-MW STGs. At ISO

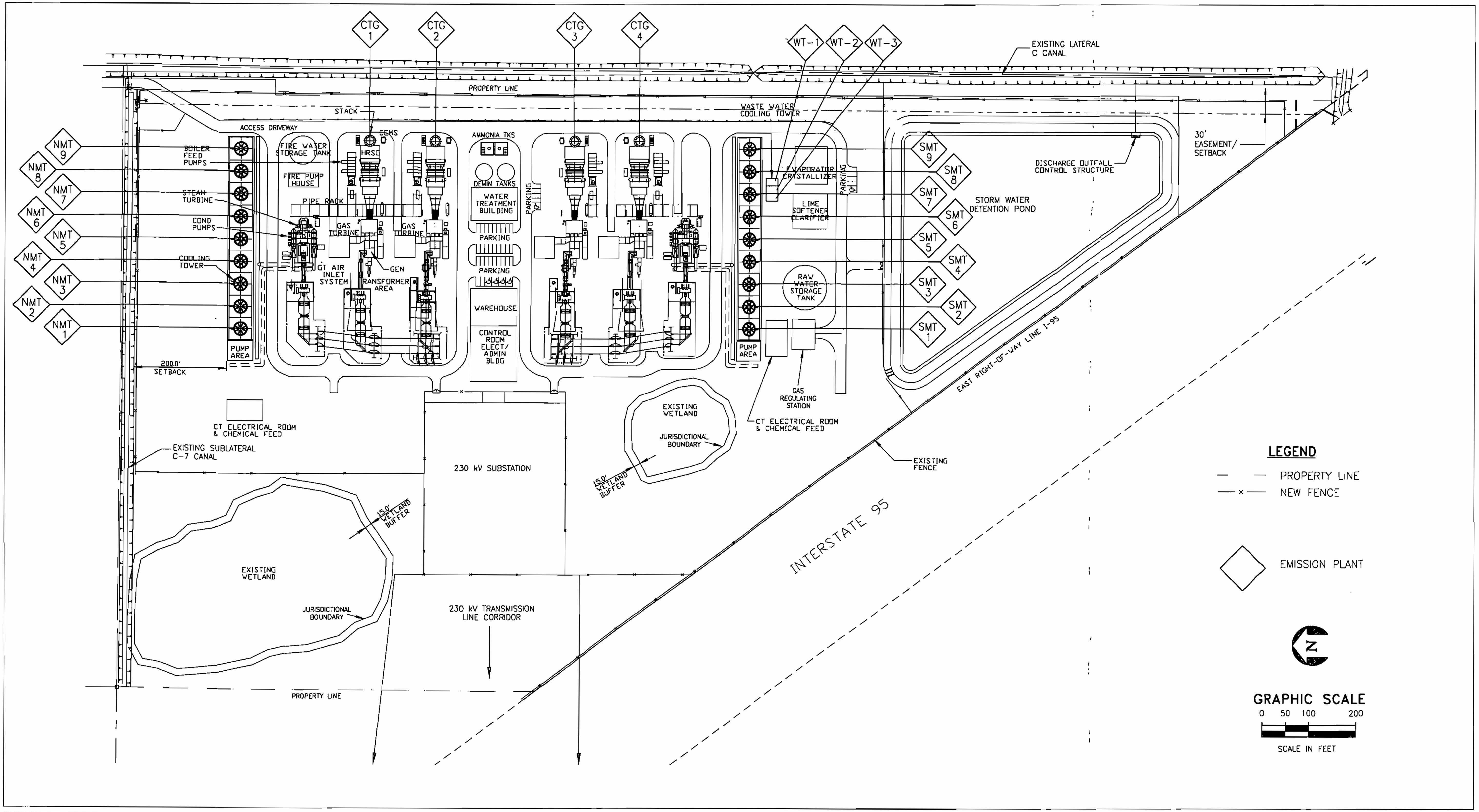

FIGURE 2.3.

GENERAL SITE LAYOUT

Sources: Burns and Roe, 2000; ECT, 2000.

conditions of 59°F ambient temperature, the BHEC will generate a nominal 1,080 MW. A process flow diagram of BHEC is presented in Figure 2-4.

CTGs are heat engines that convert latent fuel energy into *work* using compressed hot gas as the working medium. CTGs deliver mechanical output by means of a rotating shaft which is used to drive an electrical generator, thereby converting a portion of the engine's mechanical output to electrical energy. Ambient air is first filtered and then compressed by the CTG compressor. The CTG compressor increases the pressure of the combustion air stream and also raises its temperature. During warm ambient temperature conditions, the turbine inlet ambient air will be cooled by an evaporative cooler, thus providing denser air for combustion and increasing the power output. The compressed combustion air is then combined with natural gas fuel and burned in the CTG's high-pressure combustor to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power which is used to drive an electric generator as well as the CTG combustion air compressor. The CTGs will also utilize steam power augmentation (i.e., the injection of steam into the CTGs) to increase power production during periods of peak demand. Steam injection for power augmentation is different than using steam injection in the CTG combustion zone for NO_x control.

The hot exhaust gases from the CTGs next flow to the HRSGs for the production of steam. Each CTG will use an HRSG to recover exhaust heat from the CTG and produce steam to power the two STGs. Each STG, in turn, will drive an electric generator having a nominal generation capacity of 200 MW. Each of the four HRSGs will include supplemental DB firing for the production of additional steam during peak demand periods. The DBs, which will be fired exclusively with natural gas, will each have a nominal heat input rating of 289 million British thermal units per hour (MMBtu/hr), higher heating value (HHV). Following reuse of the CTG exhaust waste heat by the HRSG, the exhaust gases are discharged to the atmosphere.

Normal operation is expected to consist of all CTG/HRSG units operating at baseload. Alternate operating modes include reduced load (i.e., between 60 and 100 percent of base

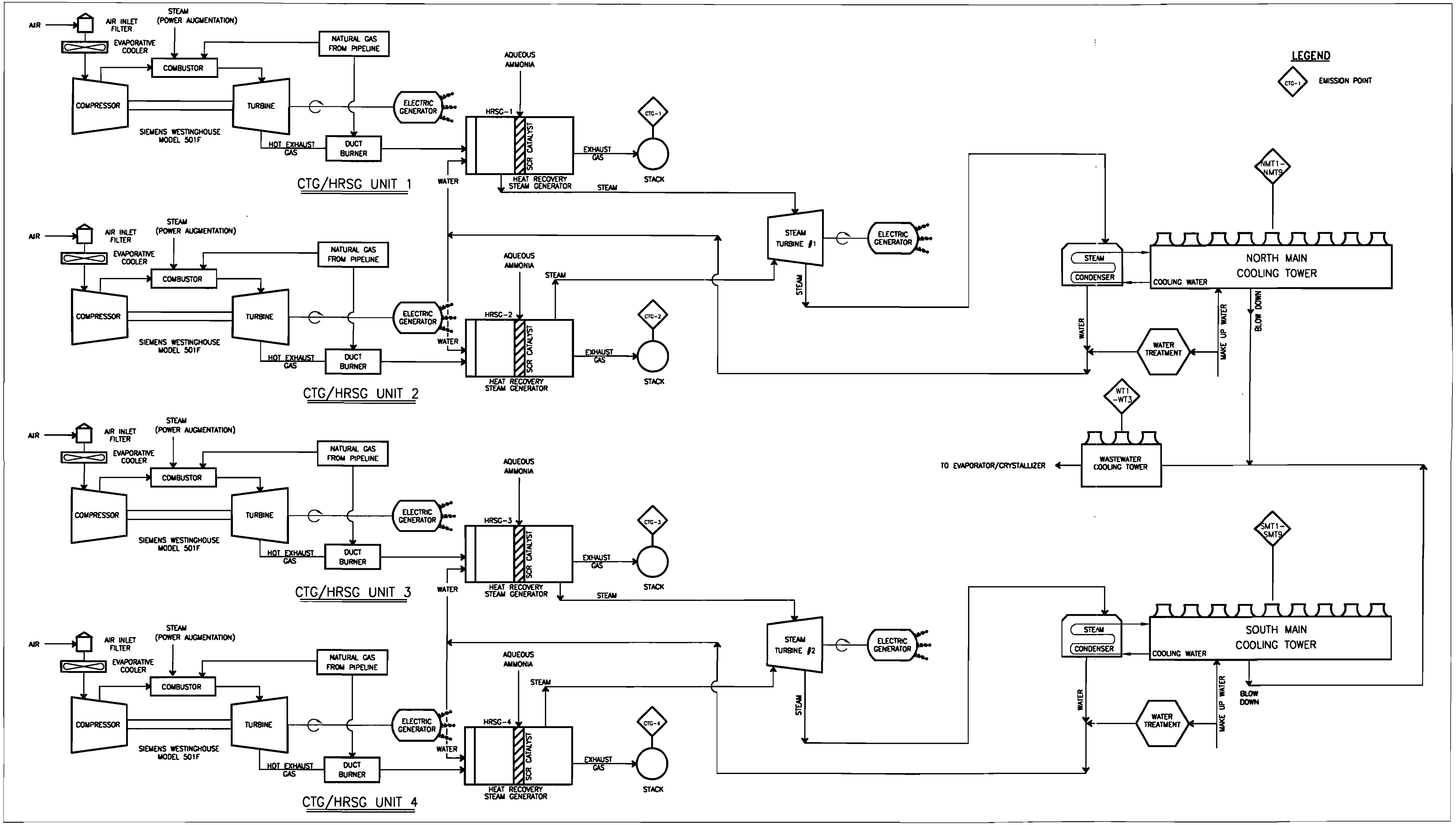

FIGURE 2-4.

PROCESS FLOW DIAGRAM

Source: ECT, 2000.

CALPINE
BLUE HERON
ENERGY CENTER

load) operation for one or more of the CTG/HRSG units depending on power demands, use of CTG inlet air evaporative cooling during warm ambient air temperature periods, and supplemental HRSG DB firing and CTG steam power augmentation during peak demand periods. Because HRSG DB firing and CTG steam power augmentation will increase CTG/HRSG emissions in comparison to normal operations, the combination operating mode of HRSG DB firing and CTG steam power augmentation will be limited to no more than 2,880 hr/yr per CTG/HRSG unit. For the same reason, CTG operations at low load (i.e., between 60- and 70-percent load) will be limited to no more than 1,500 hr/yr per CTG. The CTGs will not be designed with bypass stacks and will operate only in the CC mode. The CTG/HRSG units are designed for continuous operation (i.e., 8,760 hr/yr) and may operate at up to a 100-percent annual capacity factor.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to startup, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CTG cold start-up and shutdown periods may last for more than 2 hours in a 24-hour period, the following periods of excess emissions above the 2-hour per 24-hour limit are requested for the BHEC CTGs: (a) up to 4 hours per start-up during cold start-up to CC operation, and (b) up to 3 hours per shutdown during shutdowns from CC operation. Cold start-up is defined as a startup to CC operation following a complete shutdown lasting at least 48 hours. CTG start-up is defined as that period of time from initiation of CTG firing unit until the unit reaches steady-state load operation. Steady-state operation is reached when the CTG reaches minimum load (i.e., 60 percent load) and the STG is declared available for load changes.

The CTGs and DBs will utilize DLN combustion technology and SCR to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTGs and DBs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions. The main (i.e., the two 9-cell towers) and wastewater mechanical draft cooling towers will be equipped with drift eliminators, achieving drift loss rates of no more than 0.002 and 0.0005 percent, respectively.

2.3 EMISSION AND STACK PARAMETERS

Table 2-1 provides maximum hourly criteria pollutant CTG/HRSG emission rates. Maximum hourly noncriteria pollutant (i.e., H_2SO_4 mist) emission rates are summarized in Table 2-2. The highest hourly emission rates for each pollutant are prescribed, taking into account load and ambient temperature to develop maximum hourly emission estimates for each CTG/HRSG unit.

Maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for operations at low ambient temperature (i.e., 20°F), CTG baseload with steam power augmentation and HRSG DB firing. The bases for these emission rates are provided in Attachment C.

Table 2-3 presents projected maximum annualized criteria and noncriteria emissions for the BHEC based on an evaluation of four annual operating profiles. For NO_x, PM/PM_{10}, SO_2, and H_2SO_4 mist, maximum annualized rates were estimated for each CTG/HRSG unit assuming CTG baseload operation for 5,880 hr/yr at 59°F, and CTG baseload operation for 2,880 hr/yr at 95°F with CTG inlet air evaporative cooling, steam power augmentation, and HRSG DB firing. For CO and VOCs, the maximum annualized rates were estimated for each CTG/HRSG unit assuming CTG baseload operation for 4,380 hr/yr at 59°F; CTG operation at 60-percent load for 1,500 hr/yr at 59°F; and CTG baseload operation for 2,880 hr/yr at 95°F with CTG inlet air evaporative cooling, steam power augmentation, and HRSG DB firing.

Annual emission rate estimates for the mechanical draft cooling towers, emergency electrical generator and fire water pump diesel-fired engines, and total BHEC annual emissions are shown in Table 2-3. Details of the annualized emission calculations are also included in Attachment C. Stack parameters for the natural gas-fired CTG/HRSG units and cooling towers are provided in Tables 2-4 and 2-5, respectively.

Table 2.1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Four Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	ppmvd†	lb/hr	g/s
100	20‡	26.0	3.28	10.2	0.9	31.9	3.5	193.3	37.0	17.8	5.9	0.038	0.0048
	59	17.8	2.24	7.9	0.9	24.4	3.5	43.0	10.0	2.9	1.2	0.030	0.0037
	72††	23.8	2.99	8.9	0.9	27.9	3.5	70.9	15.5	8.6	3.3	0.033	0.0042
	95**	22.6	2.85	9.0	0.9	28.1	3.5	177.3	38.5	17.4	6.6	0.034	0.0042
70	20	15.7	1.98	6.4	0.9	19.9	3.5	35.0	10.0	4.5	2.3	0.024	0.0030
	59	14.8	1.86	6.0	0.9	18.5	3.5	32.0	10.0	4.2	2.3	0.022	0.0028
	72	14.3	1.81	5.8	0.9	17.9	3.5	32.0	10.0	4.1	2.3	0.022	0.0027
	95	13.6	1.71	5.5	0.9	17.1	3.5	30.0	10.0	3.9	2.3	0.021	0.0026
60	20	13.8	1.74	5.8	0.9	17.8	3.5	155.0	50.0	5.3	3.0	0.022	0.0027
	59	13.2	1.66	5.5	0.9	16.8	3.5	147.0	50.0	5.0	3.0	0.020	0.0026
	72	12.8	1.62	5.3	0.9	16.2	3.5	142.0	50.0	4.9	3.0	0.020	0.0025
	95	12.1	1.53	5.0	0.9	15.3	3.5	133.0	50.0	4.6	3.0	0.019	0.0023

* As measured by EPA Reference Methods 201A and 202.
† Corrected to 15-percent O_2.
‡ With steam power augmentation and duct burner firing.
†† With evaporative cooling and DB firing.
** With evaporative cooling, steam power augmentation, and duct burner firing.

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Four Ambient Temperatures (per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist lb/hr	H_2SO_4 mist g/s
100	20*	1.88	0.236
	59	1.46	0.184
	72†	1.64	0.206
	95‡	1.65	0.208
70	20	1.18	0.149
	59	1.10	0.138
	72	1.07	0.134
	95	1.02	0.128
60	20	1.06	0.134
	59	1.01	0.127
	72	0.98	0.123
	95	0.92	0.115

Note: g/s = gram per second.

*Emission rates include steam power augmentation and duct burner firing.
†Emission rates include use of evaporative cooler and duct burner firing.
‡Emission rates include use of evaporative cooler, duct burner firing, and steam power augmentation.

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

Table 2-3. Maximum Annualized Emission Rates (tpy)

Pollutant	CTG/HRSG Units	Emergency Diesel Engines	Cooling Towers	BHEC Totals
NO_x	448.2	5.0	N/A	453.2
CO	1,838.6	1.1	N/A	1,839.8
PM	339.0	0.2	113.6	452.8
PM_{10}	339.0	0.2	69.3	408.5
SO_2	145.0	0.1	N/A	145.1
VOCs	140.3	0.2	N/A	140.6
Lead	0.5	Neg.	N/A	0.5
H_2SO_4 mist	26.6	Neg.	N/A	26.6

Note: N/A = not applicable.
Neg. = negligible.

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

Table 2.4. CTG/HRSG Stack Parameters for Three Unit Loads and Four Ambient Temperatures (Per CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meter	°F	K	fps	m/sec	ft	meter
100	20‡	135	41.1	165	347	63.6	19.4	19.0	5.79
	59	135	41.1	165	347	57.1	17.4	19.0	5.79
	72††	135	41.1	165	347	56.1	17.1	19.0	5.79
	95**	135	41.1	165	347	56.0	17.1	19.0	5.79
70	20	135	41.1	165	347	50.1	15.3	19.0	5.79
	59	135	41.1	165	347	47.6	14.5	19.0	5.79
	72	135	41.1	165	347	46.8	14.3	19.0	5.79
	95	135	41.1	165	347	45.4	13.8	19.0	5.79
60	20	135	41.1	165	347	44.3	13.5	19.0	5.79
	59	135	41.1	165	347	42.3	12.9	19.0	5.79
	72	135	41.1	165	347	41.7	12.7	19.0	5.79
	95	135	41.1	165	347	40.5	12.3	19.0	5.79

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

‡ With steam power augmentation and duct burner firing.
†† With evaporative cooling and DB firing.
** With evaporative cooling, steam power augmentation, and duct burner firing.

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

Table 2.5. Cooling Tower Stack Parameters

	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
	ft	meter	°F	K	fps	m/sec	ft	meter
A. Main Cooling Tower (Per Cell)	62	18.9	106	314	26.1	7.9	33.0	10.1
B. Wastewater Cooling Tower (Per Cell)	21	6.4	100	311	38.2	11.7	10.5	3.2

Sources: Calpine, 2000.
ECT, 2000.

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, the U.S. Environmental Protection Agency (EPA) has enacted primary and secondary NAAQS for six air pollutants (40 CFR 50). Primary NAAQS are standards the attainment and maintenance of which in the judgement of the EPA Administrator, based on air quality criteria and allowing an adequate margin of safety, are requisite to protect the public health. Secondary NAAQS are standards the attainment and maintenance of which in the judgement of the EPA Administrator, based on air quality criteria, are requisite to protect the public welfare from any known or anticipated adverse effects associated with the presence of such air 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 proposed BHEC will be located in southern Indian River County adjacent to I-95, approximately 5.5 miles south-southeast of the intersection of SR 60 and I-95. Indian River County is presently designated in 40 CFR §81.310 as better than the national standards (for total suspended particulates [TSPs] and SO_2), unclassifiable/attainment (for CO), not designated (for lead), and unclassifiable or better than national standards (for nitrogen dioxide [NO_2]). EPA had previously revoked the 1-hour ozone standard for all areas of Florida in June 1998 due to adoption of a new 8-hour ozone standard. However, because of litigation involving the new 8-hour ozone standard, on July 5, 2000, EPA reinstated the 1-hour ozone standard for all counties in Florida. Presently, 40 CFR §81.310 designates all counties in Florida, including Indian River County, as unclassifiable/attainment with respect to the 1-hour ozone standard.

Indian River 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.

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

Pollutant (units)	Averaging Periods	National Standards		Florida Standards
		Primary	Secondary	
SO_2 (ppmv)	3-hour[1]		0.5	0.5
	24-hour[1]	0.14		0.1
	Annual[2]	0.030		0.02
SO_2	3-hour[1]			1,300
	24-hour[1]			260
	Annual[2]			60
PM_{10}[13]	24-hour[3]	150	150	
	Annual[4]	50	50	
PM_{10}	24-hour[5]			150
	Annual[6]			50
$PM_{2.5}$[11,12]	24-hour[7]	65	65	
	Annual[8]	15	15	
CO (ppmv)	1-hour[1]	35		35
	8-hour[1]	9		9
CO	1-hour[1]			40,000
	8-hour[1]			10,000
Ozone (ppmv)	1-hour[9]	0.12		0.12
	8-hour[10,11]	0.08	0.08	
NO_2 (ppmv)	Annual[2]	0.053	0.053	0.05
NO_2	Annual[2]			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]Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[4]Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[5]Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.
[6]Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.
[7]Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
[8]Arithmetic mean, as determined by 40 CFR 50, Appendix N.
[9]Standard attained when the expected number of 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.
[10]Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
[11]The U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court) held that these standards are not enforceable. American Trucking Association v. U.S.E.P.A., 1999 WL300618 (Circuit Court).
[12]The Circuit Court may vacate standards following briefing. Id.
[13]The Circuit Court held PM_{10} standards vacated upon promulgation of effective $PM_{2.5}$ standards.

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

3.2 NONATTAINMENT NSR APPLICABILITY

The BHEC will be located in Indian River County. As noted above, Indian River County is presently designated as either better than national standards or unclassifiable/attainment for all criteria pollutants. Accordingly, the BHEC emission sources are not subject to the nonattainment NSR requirements of Section 62-212.500, F.A.C.

3.3 PSD NSR APPLICABILITY

The BHEC CTG/HRSG units will each have a heat input greater than 250 MMBtu/hr, will be located in an attainment area, and will have potential emissions of a regulated pollutant in excess of 100 tpy. Therefore, the BHEC qualifies as a new major facility and is subject to the PSD NSR requirements of Section 62-212.400, F.A.C., for those pollutants which are emitted at or above the specified PSD significant emission rate levels.

Comparisons of estimated potential annual emission rates for the BHEC Project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, PM, PM_{10}, SO_2, CO, VOCs, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Detailed emission rate estimates for the BHEC are provided in Attachment C.

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

Pollutant	BHEC Project Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	453.2	40	Yes
CO	1,839.8	100	Yes
PM	452.8	25	Yes
PM_{10}	408.5	15	Yes
SO_2	145.1	40	Yes
Ozone/VOC	140.6	40	Yes
Lead	0.5	0.6	No
Mercury	0.0013	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	26.6	7	Yes
Total reduced sulfur (including hydrogen sulfide)	Not Present	10	No
Reduced sulfur compounds (including hydrogen sulfide)	Not Present	10	No
Municipal waste combustor acid gases (measured as SO_2 and hydrogen chloride)	Not Present	40	No
Municipal waste combustor metals (measured as PM)	Not Present	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not Present	3.5×10^{-6}	No

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 2000.

4.0 PSD NSR REQUIREMENTS

4.1 CONTROL TECHNOLOGY REVIEW

Pursuant to Rule 62-212.400(5)(c), F.A.C., an analysis of BACT is required for each pollutant which is emitted by the proposed BHEC in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(42), F.A.C., BACT is:

> "an emission limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation. Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results."

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant which exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units involved in a major modification or a new major source that emit or increase emissions of the applicable pollutants 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 unless determined to be infeasible. 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) or national emission standard for hazardous air pollutants (NESHAPs), or any other emission limitation established by state regulations.

BACT analyses are conducted using the *top-down* analysis approach, which was outlined in a December 1, 1987, memorandum from Craig Potter, EPA Assistant Administrator, to EPA Regional Administrators on the subject of *Improving New Source Review (NSR) Implementation*. Using the top-down methodology, available control technology alternatives are identified based on knowledge of the particular industry of the applicant and previous control technology permitting decisions for other identical or similar sources. These alternatives are rank ordered by stringency into a control technology hierarchy. The hierarchy is evaluated starting with the *top*, or most stringent alternative, to determine economic, environmental, and energy impacts, and to assess the feasibility or appropriateness of each alternative as BACT based on site-specific factors. If the top control alternative is not applicable, or is technically or economically infeasible, it is rejected as BACT, and the next most stringent alternative is then considered. This evaluation process continues until an applicable control alternative is determined to be both technologically and economically feasible, thereby defining the emission level corresponding to BACT for the pollutant in question emitted from the particular facility under consideration.

4.2 AMBIENT AIR QUALITY MONITORING

In accordance with the PSD requirements of Rule 62-212.400(5)(f), F.A.C., any application for a PSD permit must contain, for each pollutant subject to review, an analysis of ambient air quality data in the area affected by the proposed major stationary source or major modification. The affected pollutants are those that the source would potentially emit in significant amounts; i.e., those that exceed the PSD significant emission rate thresholds shown in Table 3-2.

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

Rule 62-212.400(2)(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 shall be exempt from the monitoring requirements of Rule 62-212.400(5)(f) and (g), F.A.C., with respect to a particular pollutant if the emissions increase of the pollution from the source or modification would cause, in any area, air quality impacts less than the PSD *de minimis* ambient impact levels presented in Rule 62-212.400, Table 212.400-3, F.A.C. (see Table 4-1). In addition, an exemption may be granted if the air quality impacts due to existing sources in the area of concern are less than the PSD *de minimis* ambient impact levels.

Applicability of the PSD preconstruction ambient monitoring requirements to the BHEC is discussed in Section 8.0.

4.3 AMBIENT IMPACT ANALYSIS

An air quality or source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rates (see Table 3-2). 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* as published in Appendix W to 40 CFR Part 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

Table 4-1. PSD *De Minimis* Ambient Impact Levels

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

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

below the appropriate Rule 62-210.200(259), F.A.C., significant impact level, as presented in Table 4-2.

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

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

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality *baseline concentration* level for SO_2 and TSP would constitute significant deterioration. The magnitude of the increment that cannot be exceeded depends on the classification of the area in which a new source (or modification) will have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 2,024 hectares [ha] [5,000 acres], and national parks larger than 2,428 ha [6,000 acres]) or Class II (all other areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. However, the states were given the authority to redesignate any Class II area to Class III status, provided certain requirements were met. EPA then promulgated, as regulations, the requirements for classifications and area designations.

Table 4-2. Significant Impact Levels

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

Source: Rule 62-210.200(260), F.A.C.

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 March 28, 1988, for Florida; new major sources or modifications constructed after this date will consume NO_2 increment.

On June 3, 1993, EPA promulgated PSD increments for PM_{10}; the effective date of the new regulation was June 3, 1994. The increments for PM_{10} replace the original PM increments which were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which includes a revised NAAQS for PM_{10} and a new NAAQS for particulate matter less than or equal to 2.5 micrometers ($PM_{2.5}$), became effective on September 16, 1997. The new NAAQS for $PM_{2.5}$ has been recently remanded to EPA and is not currently effective. In addition, due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for State permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

Current Florida PSD allowable increments are specified in Section 62-204.260, F.A.C., and shown on Table 4-3.

The term *baseline concentration* evolved from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition in the PSD regulations, as amended, *baseline concentration* means the ambient concentration level that exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established based on:

1. The actual emissions representative of sources in existence on the applicable minor source baseline date.

Table 4-3. PSD Allowable Increments (μg/m³)

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

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

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

2. The allowable emissions of major stationary sources which 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:

1. Actual emissions from any major stationary source on which construction commenced after the major source baseline date.
2. 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 (in Florida, December 27, 1977, for PM/PM_{10} and SO_2; and March 28, 1988 for NO_x) 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 analysis for the BHEC is provided in Sections 6.0 (methodology) and 7.0 (results).

4.4 ADDITIONAL IMPACT ANALYSES

Rule 62-212.400(5)(e), F.A.C., requires additional impact analyses for three areas: (1) associated growth, (2) soils and vegetation impact, and (3) visibility impairment. The level of analysis for each area should be commensurate with the scope of the project under review. A more extensive analysis would be conducted for projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

1. A projection of the associated industrial, commercial, and residential growth that will occur in the area.
2. An estimate of the air pollution emissions generated by the permanent associated growth.
3. 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 under review.

The additional impact analyses for the BHEC is provided in Section 9.0.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

BACT analyses were performed in accordance with the EPA top-down method as previously described in Section 4.1. The first step in the top-down BACT procedure is the identification of all available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives included:

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar combustion turbine 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, 1990). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low, in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed. The economic analysis employed the procedures found in the Office of Air Quality Planning and Standards (OAQPS) *Control Cost Manual* (EPA, 1996). Table 5-1 summarizes specific factors used in estimating capital and annual operating costs.

Table 5-1. Capital and Annual Operating Cost Factors

Cost Item	Factor
Direct Capital Costs	
Instrumentation	0.10 x equipment cost
Sales tax	0.06 x equipment cost
Freight	0.05 x equipment cost
Foundations and supports	0.08 x purchased equipment cost
Handling and erection	0.14 x purchased equipment cost
Electrical	0.04 x purchased equipment cost
Piping	0.02 x purchased equipment cost
Insulation	0.01 x purchased equipment cost
Painting	0.01 x purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 x purchased equipment cost
Construction and field expenses	0.05 x purchased equipment cost
Contractor fees	0.10 x purchased equipment cost
Start-up	0.02 x purchased equipment cost
Performance testing	0.01 x purchased equipment cost
Contingencies	0.03 x purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 x total operator labor cost
Maintenance materials	1.00 x total maintenance labor cost
Emission fee credit	$25 per ton
Indirect Annual Operating Costs	
Overhead	0.60 x total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 x total capital investment
Property taxes	0.01 x total capital investment
Insurance	0.01 x total capital investment

Source: EPA, 1996.

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

As indicated in Section 3.3, Table 3-2, BHEC potential emission rates of NO_x, CO, SO_2, H_2SO_4 mist, VOCs, PM, and PM_{10} exceed the PSD significance rates and, therefore, are subject to BACT analysis. Control technology analyses using the five-step top-down BACT method are provided in Sections 5.3, 5.4, and 5.5 for combustion products (PM/PM_{10}), products of incomplete combustion (CO and VOCs), and acid gases (NO_x, SO_2, and H_2SO_4 mist), respectively.

5.2 FEDERAL AND FLORIDA EMISSION STANDARDS

Pursuant to Rule 62-212.400(5)(b), F.A.C., BACT emission limitations must be no less stringent than any applicable NSPS (40 CFR Part 60), NESHAPs (40 CFR Parts 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

On the federal level, emissions from gas turbines are regulated by NSPS Subpart GG. Subpart GG establishes emission limits for gas turbines that were constructed after October 3, 1977, and that meet any of the following criteria:

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 MMBtu/hr based on the LHV of the fuel.
- Stationary gas turbines with a heat input at peak load between 10 and 100 MMBtu/hr based on the fuel LHV.
- Stationary gas turbines with a manufacturer's rated baseload at ISO standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The BHEC CTGs qualify as electric utility stationary gas turbines and, therefore, are subject to the NO_x and SO_2 emission limitations of NSPS 40 CFR 60, Subpart GG, 60.332(a)(1) and 60.333, respectively.

BHEC HRSG DBs each have a rated heat input greater than 250 MMBtu/hr and, therefore, are subject to the requirements of NSPS Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978*. Specifically, emissions from the DBs are limited to no more than 0.03 lb PM /MMBtu per §60.42a(a)(1); 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity per §60.42a(b); 0.20 lb SO_2/MMBtu (30-day rolling average) per §60.43a(b)(2); and 1.6 lb NO_x/MW-hr (30-day rolling average) per §60.43a(d)(1).

There are no NESHAPS which are applicable to the BHEC emission sources. BHEC CTGs will have potential emissions of hazardous air pollutants (HAPs) less than the major source thresholds of 10 tpy for any individual HAP and 25 tpy for total HAPs. BHEC is, therefore, not subject to the case-by-case maximum achievable control technology (MACT) requirements of Section 112(g)(2)(B) of the 1990 CAA Amendments. Note that the 1990 CAA Amendments specifically excludes "electric utility steam generating units" from Section 112(g)(2)(B) and the development of NESHAPS, unless and until such time as this category is added to the source category list under Section 112(c)(5). In the April 21, 2000, Federal Register, EPA issued an interpretative rule which states that a CC system HRSG meets the definition of an "electric utility steam generating unit". HAP emissions from the BHEC HRSG DBs are, therefore, excluded in the determination of Section 112(g)(2)(B) applicability.

FDEP emission standards for stationary sources are contained in Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*. Visible emissions are limited to a maximum of 20 percent opacity pursuant to Rule 62-296.320(4)(b), F.A.C. Sections 62-296.401 through -.417, F.A.C., specify emission standards for 17 categories of sources; none of these categories are applicable to CTGs. Rule 62-296.405(2) contains visible emissions, PM, SO_2, and NO_x limitations for new fossil fuel steam generators with more than 250 MMBtu/hr heat input which are applicable to the BHEC HRSG DBs. For each air contaminant, Rule 62-296.405(2) references Rule 62-204.800(7) and 40 CFR Subpart Da. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subparts Da and GG.

Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment and maintenance areas) and 62-296.700, F.A.C. (for PM nonattainment and maintenance areas). Because BHEC will be located in Indian River County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAPs, respectively, by reference. As noted previously, NSPS Subpart Da, *Electric Utility Steam Generating Units for Which Construction Commenced After September 18, 1978* and Subpart GG, *Stationary Gas Turbines* are applicable to the BHEC HRSG DBs and CTGs, respectively. There are no applicable NESHAPs requirements.

Applicable federal and state emission standards are summarized in Tables 5-2 and 5-3, respectively. Detailed calculations of NSPS Subpart GG NO_x limitations are provided in Attachment D. BACT emission limitations proposed for BHEC are all more stringent than the applicable federal and state standards cited in these tables.

5.3 BACT ANALYSIS FOR PM/PM_{10}

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

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

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

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

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	STD = 0.0075 x (14.4/Y) + F

where: STD = allowable NO_x emissions (percent by volume at 15 percent O_2 and on a dry basis).

Y = manufacturer's rated heat rate in kilojoules per watt hour at manufacturer's rated load, or actual measured heat rate based on LHV of fuel as measured at actual peak load. Y cannot exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen per:

FBN = fuel bound nitrogen.

FBN (weight percent)	F (NO_x - volume percent)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04 x N
$0.1 < N \leq 0.25$	0.004 + 0.0067 x (N-0.1)
$N > 0.25$	0.005

where: N = nitrogen content of fuel; percent by weight.

SO_2 = $\leq$0.015 percent by volume at 15 percent O_2 and on a dry basis; or fuel sulfur content $\leq$0.8 weight percent.

NSPS Subpart Da, Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.

Pollutant	Emission Limitation
NO_x	1.6 lb/MW-hr (gross output)
SO_2	0.20 lb/MMBtu
PM	0.03 lb/MMBtu
Opacity	20 percent

Sources: 40 CFR 60, Subparts Da and GG.

Table 5-3. Florida Emission Limitations

Pollutant	Emission Limitation
General Visible Emissions Standard Rule 62-296.320(4)(b)1., F.A.C.	
• Visible emissions	<20-percent opacity (averaged over a 6-minute period)

Source: Chapter 62-296, F.A.C.

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 and distillate fuel oil combustion are typically less than 1.0 micron in size.

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

A fabric filter system consists of a number of filtering elements, bag cleaning system, main shell structure, dust removal system, and fan. PM/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 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.

While all of these postprocess technologies would be technically feasible for controlling PM/PM_{10} emissions from CTGs and HRSG DBs, none of the previously described control equipment have been applied to these types of combustion sources 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 BHEC CTGs and HRSG DBs will be fired exclusively with natural gas. Combustion of natural gas will generate low PM/PM_{10} emissions in comparison to other fuels due to its negligible ash and sulfur contents. The minor PM/PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM/PM_{10} concentrations. The estimated PM/PM_{10} exhaust concentration for the BHEC CTG/HRSGs at baseload and 59°F is approximately 0.003 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM/PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

PM/PM_{10} emissions will also occur due to cooling tower operations. BHEC will include two 9-cell main cooling towers (i.e., the north and south main cooling towers) and one small three-cell wastewater 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.

The only feasible technology for controlling PM/PM_{10} from 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. 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.

Factors affecting cooling tower PM/PM_{10} emission rates include drift droplet loss rate (expressed as a percent of recirculating cooling water flow rate), concentration of dissolved solids in the recirculating cooling water, and the recirculating cooling water flow rate (i.e., size of the tower).

PM/PM_{10} emissions from the BHEC cooling towers will be controlled using high efficiency drift eliminators. The two main north and south cooling towers will achieve a drift loss rate of no more than 0.002 percent of the cooling tower recirculating water flow. Due to the zero wastewater discharge design planned for the BHEC, the wastewater cooling tower recirculating water contains a significantly higher concentration of dissolved solids than the main cooling towers. For this reason, the wastewater cooling tower has been designed to achieve a drift loss rate of no more than 0.0005 percent of the wastewater cooling tower recirculating water flow.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

BACT PM/PM_{10} limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-4. Recent Florida PM/PM_{10} BACT determinations for natural gas-fired CTGs are shown in Table 5-5. All determinations are based on the use of clean fuels

Table 5-4. RBLC PM Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	2.5 LBS/HR (GAS)	EFFICIENT OPERATION OF THE COM- BUSTION TURBINE	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0110	SOUTHERN NATURAL GAS	WARD	3/4/98	4/24/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)		0.01 LBS/MMBTU	CLEAN FUEL - NATURAL GAS/HYDROGEN	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW	0.012 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	4.3 LB/DAY	NATURAL GAS, AIR INTAKE COOLER	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.012 LB/MMBTU	OPACITY LIMIT APPLIES TO LUBE OIL VENTS.	LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25.8 LB/H	FUEL SPEC: NATURAL GAS FIRED	OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	33311	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	5 LB/H	GOOD COMBUSTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEAOE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	7 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	7 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	0.0136 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	0.0136 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	9 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	7 LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	7 LB/HR AT 20 F	FUEL SPEC: LOW SULFUR FUELS	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.006 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	0.006 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	0.0064 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	0.0064 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	18 LB/HR	CLEAN FUEL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	35158	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	18 LB/HR	CLEAN FUEL	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	5 LBS/HR		BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	92 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	18.3 LB/HR	NO CONTROL CLEAN FUEL	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	12.5 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	0.06 LB/MMBTU		BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	0.06 LB/MMBTU		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	0.06 LB/MMBTU		BACT-OTHER
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	0.06 LB/MMBTU		BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	5 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0066	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	5 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0023 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.0023 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	0.006 LB/MMBTU	TURBINE DESIGN	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	SEE P2 DESC.	COMBUSTION AIR FILTERS	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATIC	HOBBS	35373	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW			BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	5.3 LBS/HR	HIGH COMBUSTION EFFICIENCY	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	7.8 LB/H PER TURBINE	GOOD COMBUSTION PRACTICES	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	30.6 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE COMBUSTOR	BACT-PSD
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	0.004 LB/MMBTU GAS (BASE)	COMBUSTION CONTROLS AND LOW SULFUR OIL	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	0.004 LB/MMBTU, GAS	COMBUSTION CONTROLS AND LOW SULFUR OIL	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	0.0062 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	33913	9/13/94	TURBINE, COMBUSTION (79 MW)	653 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.035 LB/MMBTU	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360 MMBTU/HR	8 LB/HR		BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	0.0015 % OF FLOW	TWO STAGE MIST ELIMINATOR TO RESTRICT DRIFT.	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	12 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	59 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES	BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	0.005 LB/MMBTU, GAS		BACT-PSD
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	45 LBS/HR	FUEL SPEC: LOW ASH CONTENT FUELS	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5 MM BTU/HR TURBINES	3.79 TPY		BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	52 TPY	INTERNAL COMBUSTION CONTROLS	BACT

Source: RBLC 2000.

MAXIMUM	0.0600 LB/MMBTU
MINIMUM	0.0023 LB/MMBTU
MEDIAN	0.0065 LB/MMBTU

Table 5-5. Florida BACT PM Emission Limitation Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size MW	Turbine Size MMBtu/hr	PM Emission Limit lb/hr	PM Emission Limit lb/MMBtu	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	857	9.0	0.01	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,214	10.5	0.0134	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	367	(9.0)	0.0245	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	869	7.0	0.0100	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,615	9.0	(0.0056)	Combustion design and clean fuels
09/28/93	Florida Gas Transmission	N/A	32	0.64	N/A	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,755	17.0	0.013	Combustion design and clean fuels
02/25/94	Florida Power Corp. Polk County Site	235	1,510	9.0	0.006	Combustion design and clean fuels
03/07/95	Orange Cogeneration, L.P.	39	388	5.0	(0.013)	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	403	5.0	0.0065	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	971	7.0	(0.0072)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		7.0		Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,468	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,174	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,757	15.6	(0.0089)	Combustion design and clean fuels
11/25/98	FP&L Ft. Myers Plant Repowering	170	1,760	—	—	Combustion design and clean fuels
12/04/98	Santa Rosa Energy Center	167	1,780	(8.2)	0.0051	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

and good combustion practice. Table 5-6 provides RBLC database PM/PM_{10} BACT determinations for cooling towers. A recent Florida PM/PM_{10} BACT determination for cooling towers is the 0.002 percent drift loss rate limit made for the City of Tallahassee Purdom Unit 8. The recent May 10, 2000, draft FDEP PSD permit for the Osprey Energy Center also established a drift loss rate of 0.002 percent as PM/PM_{10} BACT for freshwater cooling towers.

Because post-process stack controls for PM/PM_{10} are not appropriate for CTGs and HRSG DBs, the use of good combustion practices and clean fuels is considered to be BACT. BHEC CTGs and HRSG DBs will use the latest, advanced combustor technology to maximize combustion efficiency and minimize 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 CTGs and HRSG DBs will be fired exclusively with pipeline quality natural gas. 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 CTG/HRSG units, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM/PM_{10}. Table 5-7 summarizes the PM_{10} BACT emission limit proposed for the BHEC CTGs and HRSG DBs.

5.4 BACT ANALYSIS FOR CO AND VOCS

CO and VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO and VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO and VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Decreased combustion zone temperature due to the injection of water or steam for NO_x control will also result in an increase in CO and VOC 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 and VOC emission

Table 5-6. RBLC PM Summary - Cooling Towers

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Last Update	Process Description	Thruput Rate	Emission Lmits	Control System Description	Basis
CA-0713	TEXACO REFINING AND MARKETING, INC.	BAKERSFIELD	01/19/1996	11/23/1996	COOLING TOWER	18,000 GAL PER MIN	30.2 LB/DAY	CELLULAR TYPE DRIFT ELIMINATOR	BACT-OTHER
FL-0050	FLORIDA POWER CORPORATION	CRYSTAL RIVER	08/30/1990	05/14/1993	COOLING TOWER, 4 EACH	735,000 G/M SALT WATER	0.004 % OF CIRCULATION WATER	DRIFT ELIMINATOR	BACT-PSD
NJ-0016	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	09/04/1992	08/08/1994	COOLING TOWER, MECHANICAL DRAFT	27,000,000 LB/H H2O RECIRC.	0.909 LB/HR	DRIFT ELIMINATOR	BACT-PSD
NJ-0019	CROWN/VISTA ENERGY PROJECT (CVEP)	WEST DEPTFORD	10/01/1993	08/31/1994	COOLING TOWER (2)		5.9 LB/HR	DRIFT ELIMINATOR	BACT-PSD

Source: RBLC, 2000.

Table 5-7. Proposed PM/PM_{10} BACT Emission Limits

Emission Source	Proposed PM/PM_{10} BACT Emission Limits
Each CTG/HRSG Unit	10 percent opacity
Main North and South Cooling Towers	0.002 percent drift
Wastewater Cooling Tower	0.0005 percent drift

Source: ECT, 2000.

rates. Emissions of NO_x and CO/VOC are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO and VOC emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and CO/VOC formation in order to develop units which achieve acceptable emission levels for all three pollutants.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO and VOCs from gas turbines and duct burners: (1) combustion process design and (2) oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Due to the high combustion efficiency of CTG and DBs, approximately 99 percent, CO and VOC emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO and VOCs to carbon dioxide (CO_2) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO and VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO and VOCs 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; higher temperatures on the order of 900°F are needed to oxidize VOCs. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst which 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 combustion turbine applications, oxidation catalyst systems are typically designed to achieve a control efficiency of 80 to 90 percent for CO. VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical CTG VOC control efficiency using an oxidation catalyst control system is 30 percent.

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 and VOCs. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO_2 in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO_3). SO_3 will, in turn, combine with moisture in the gas stream to form H_2SO_4 mist. Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be an appropriate control technology for combustion devices that are fired with fuels containing significant amounts of sulfur.

Technical Feasibility

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the BHEC CTGs and DBs. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO and VOC are provided in the following sections.

5.4.2 ENERGY AND ENVIRONMENTAL IMPACTS

There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO and VOC emissions.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing high sulfur contents. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas.

Because CO and VOC emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in minimal air quality improvements; i.e., below the defined PSD significant impact levels for CO and negligible reductions in ambient VOC levels. The BHEC location (Indian River County, Florida) is classified attainment for all criteria pollutants. From an air quality perspective, the only potential benefit of CO oxidation catalyst is to prevent the possible formation of a localized area with elevated concentrations of CO. The catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO_2. Dispersion modeling of BHEC CO emissions indicate that maximum CO impacts, without oxidation catalyst, will be insignificant.

The application of oxidation catalyst technology to a gas turbine will result in an increase in back pressure on the CTG due to a pressure drop across the catalyst bed. The increased back pressure will, in turn, constrain turbine output power thereby increasing the unit's heat rate. An oxidation catalyst system for the BHEC CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.0 inch of water (H_2O). This pressure drop will result in a 0.2 percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 2,978,400 kilowatt-hours (kwh) (10,163 MMBtu) per year at baseload (170-MW) operation and 100 percent capacity factor per CTG. This energy penalty is equivalent to the use of 38.7 million cubic feet (ft^3) of natural gas annually based on a natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3) for all four CTGs. The lost power generation energy penalty, based on a power cost of $0.037/kwh, is $440,803 per year for all four CTGs.

5.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-8. Specific capital and annual operating costs for the oxidation catalyst control system are summarized in Tables 5-9 and 5-10.

The base case BHEC annual CO emission rate (i.e., for all four CTG/HRSG units) is 1,838.6 tpy based on CTG baseload operation for 4,380 hr/yr at 59°F; CTG operation at 60-percent load for 1,500 hr/yr at 59°F; and CTG baseload operation for 2,880 hr/yr at 95°F with CTG inlet air evaporative cooling, steam power augmentation, and HRSG DB firing. The controlled annual CO emission rate, based on a 90 percent control efficiency, is 183.9 tpy. Base case and controlled CO emission rates are summarized in Table 5-11.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $1,553 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible. For example, the California San Joaquin Valley Unified Air Pollution Control District's BACT policy considers CO control costs of less than $300 per ton to be cost effective; i.e., CO control costs equal to or greater than $300 per ton are not considered cost effective. Results of the oxidation catalyst economic analysis are summarized in Table 5-11.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO and VOCs from CTGs and DBs is typically required only for facilities located in CO and/or ozone nonattainment areas. BACT CO and VOC limits obtained from the RBLC database for natural gas-fired CTGs are provided in Tables 5-12 and 5-13, respectively. A summary of recent FDEP CO and VOC BACT determinations for natural gas-fired combustion turbines are provided in Table 5-14 and 5-15.

Table 5-8. Economic Cost Factors

Factor	Units	Value
Interest rate	%	10.0
Control system life	Years	15
Oxidation catalyst life	Years	3*
SCR and SCONOx™ catalyst life	Years	3*
Aqueous ammonia cost	$/ton	113
Natural gas cost	$/ft^3	0.00388
Steam cost	$/lb	0.006
Electricity cost	$/kWh	0.037
Labor costs (base rates)	$/hour	
Operator		25.00
Maintenance		25.00

*Control system vendor guarantee.

Sources: Calpine, 2000.
ECT, 2000.

Table 5-9. Capital Costs for Oxidation Catalyst System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	3,520,000	A
Sales tax	211,200	0.06 x A
Instrumentation	352,000	0.10 x A
Freight	176,000	0.05 x A
Subtotal Purchased Equipment	**4,259,200**	**B**
Installation		
Foundations and supports	340,736	0.08 x B
Handling and erection	596,288	0.14 x B
Electrical	170,368	0.04 x B
Piping	85,184	0.02 x B
Insulation for ductwork	42,592	0.01 x B
Painting	42,592	0.01 x B
Subtotal Installation Cost	**1,277,760**	
Total Direct Costs (TDC)	**5,536,960**	
Indirect Costs		
Engineering	425,920	0.10 x B
Construction and field expenses	212,960	0.05 x B
Contractor fees	425,920	0.10 x B
Startup	85,184	0.02 x B
Performance test	42,592	0.01 x B
Contingency	127,776	0.03 x B
Total Indirect Costs (TIC)	**1,320,352**	
TOTAL CAPITAL INVESTMENT (TCI)	**6,857,312**	TDC + TIC

Source: ECT, 2000.

Table 5-10. Annual Operating Costs for Oxidation Catalyst System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Operator Labor	13,688	
Maintenance Labor and Material	27,376	
Subtotal Labor and Maintenance Costs	**43,116**	C
Catalyst costs		
Replacement (materials and labor)	3,422,000	3-yr replacement
Annualized Catalyst Costs	**1,376,037**	
Energy Penalties		
Turbine backpressure	440,803	0.2% penalty
Emission fee credit	(41,369)	$25/ton
Total Direct Costs (TDC)	**1,818,586**	
Indirect Costs		
Overhead	25,869	0.60 x C
Administrative charges	137,146	0.02 x TCI
Property taxes	68,573	0.01 x TCI
Insurance	68,573	0.01 x TCI
Capital recovery	451,653	15 yrs @ 10.0%
Total Indirect Costs (TIC)	**751,815**	
TOTAL ANNUAL COST (TAC)	**2,570,402**	TDC + TIC

Sources: Calpine, 2000.
ECT, 2000.

Table 5-11. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	42.0	183.9	1,654.8	6,857,312	2,570,402	1,553	40,651	Y	Y
Baseline	419.8	1,838.6	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Four Siemens Westinghouse 501F CTG/HRSG units.

Sources: Calpine, 2000.
ECT, 2000.
Engelhard, 2000.
Siemens Westinghouse, 2000.

Table 5-12. RBLC CO Summary for Natural Gas Fired CTGs (Page 1 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12600 BHP	0.42 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY COMBUSTION CON'	BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	28 PPMVD@15% O2 (GAS)	PROPER DESIGN AND GOOD COMBUSTION PRACTICES	BACT-PSD
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)				BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW			BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.165 LB/MMBTU	- EFFICIENT COMBUSTION	BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	BACT-PSD
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	10.5 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	60 PPM @ 15% O2	LEAN BURN	BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.64 MMBTU/H	7.74 PPM @ 15% O2	HIGH TEMPERATURE OXIDATION CATALYST	BACT-PSD
CA-0463	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	5/31/92	TURBINE, GAS FIRED, SOLAR MODEL H	5500 HP	7.74 PPM @ 15% O2	HIGH TEMP OXIDATION CATALYST	BACT-PSD
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		10 PPM @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	4/19/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25 MW	669.19 LB/D	OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	4/19/99	TURBINE, GE, COGENERATION, 48 MW	48 MW	252.6 LB/D	OXIDATION CATALYST	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	22.4 PPM @ 15% O2		BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33 MW	250 T/YR, LESS THAN	CO CATALYST	OTHER
CT-0130	BRIDGEPORT ENERGY, LLC	BRIDGEPORT	6/29/98	1/21/99	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TURBINE	10 PPM GAS & OIL	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL E	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	33394	3/24/95	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	30 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	30 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1614.8 MMBTU/H	49 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	54 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	40 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-00B0	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-00B0	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-00B2	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS STANDARD ONLY APPLIES IF	BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	34970	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION	BACT-PSD
FL-0116	SANTA ROSA ENERGY LLC	NORTHBROOK	12/4/98	4/16/99	TURBINE, COMBUSTION, NATURAL GAS	241 MW			BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED	BACT-PSD
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	60 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	165.9 LB/HR	COMBUSTION CONTROL	BACT
LA-00B9	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSG, GAS COGENERATION	450 MM BTU/HR	25.8 LB/HR	PROPER OPERATION	BACT-PSD
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	972.4 TPY CAP FOR 3 TURB.	GOOD COMBUSTION PRACTICE AND PROPER OPERATIC	BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	198.6 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE	BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	32842	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
MA-0016	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/B9	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	ENGINES, CHILLER, NATURAL GAS-FIRED, TWO	23.4 MMBTU/H	0.4 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	5.97 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	20 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	15 PPM @15% O2	USING 15 % EXCESS AIR.	BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175 MW	9 PPMVD @15% O2 GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	359B9	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 MW EACH	20 PPM @ 15% O2	15% EXCESS AIR	BACT-PSD
MI-0206	KALAMAZOO POWER LIMITED	COMSTOCK	12/3/91	3/23/94	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1805.9 MMBTU/H	20 PPMV	DRY LOW NOX TURBINES	BACT-PSD
MI-0244	WYANDOTTE ENERGY	WYANDOTTE	2/8/99	4/19/99	TURBINE, COMBINED CYCLE, POWER PLANT	500 MW	3 PPM	CATALYTIC OXIDIZER	LAER
NC-0065	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	59 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 MMBTU/HR	0.0055 LB/MMBTU	CATALYTIC OXIDATION	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617 MMBTU/HR (EACH)	1.8 PPMDV	OXIDATION CATALYST	OTHER
NJ-0031	UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NEWARK	6/26/97	2/17/99	COMBUSTION TURBINE COGENERATION UNITS, 3	56 MMBTU/H	75 PPMVD NAT. GAS		RACT
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11257 HP	50 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	ENGINE, GAS-FIRED, RECIPROCATING	1000 HP	2.5 G/B-HP-H	CLEAN/LEAN BURN TECHNOLOGY	BACT-PSD
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/26/95	TURBINES, NATURAL GAS (2)	5500 HP	13.2 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY.	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	27.6 PPM @ 15% O2		BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	SEE FACILITY NOTES	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100 MW	27 LBS/HR	DRY LOW-NOX TECHNOLOGY BY MAINTAINING PROPEF	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	18 PPM	GOOD COMBUSTION PRACTICES	BACT-PSD

Table 5-12. RBLC CO Summary for Natural Gas Fired CTGs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 EACH)	152.5 TPY (EACH TURBINE)	PRECISION CONTROL FOR THE LOW NOX COMBUSTOR	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240 MW	4 PPM @ 15% O2		LAER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1173 MMBTU/HR (EACH)	10 PPM	COMBUSTION CONTROLS	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1173 MMBTU/HR	25 PPM	COMBUSTION CONTROL	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1123 MMBTU/HR (EACH)	3 PPM	OXIDATION CATALYST	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GENERATOR, EMERGENCY (NATURAL GAS)	1.5 MMBTU/HR	6.5 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	33932	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS	BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSI	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	7/7/94	1/27/99	TURBINES, NATURAL GAS (2)	1696 MMBTU/H	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	110 T/YR	OXIDATION CATALYST	OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153 MW	3.1 PPM @ 15% O2	OXIDATION CATALYST 16 PPM @ 15% O2 WHEN FIRIN	OTHER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 MW	50 PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	33 PPMDV	COMBUSTION CONTROLS.	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	100 PPMDV AT MIN. LOAD	COMBUSTION CONTROLS.	BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1360 MMBTU/H EACH	11 PPM @ 15% O2, GAS		BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49 MMBTU/H	0.114 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 MEGAWATTS	23 LBS/HR	GOOD COMBUSTION PRACTICES	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3 MW (TOTAL POWER)	300 TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-023B	COMMONWEALTH CHESAPEAKE CORPORATION	NEW CHURCH	5/21/96	7/21/97	3 COMBUSTION TURBINES (OIL-FIRED)	6000 HRS/YR	96 TPY	GOOD COMBUSTION OPERATING PRACTICES	BACT/NSPS
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	CO CATALYST	BACT-PSD
WY-0032	QUESTAR PIPELINE CORP. - RK SPRINGS COMPRESSOR COM	ROCK SPRINGS	9/25/97	2/1/99	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 2EA	1001 HP	3.5 G/B-HP-H		BACT-PSD
WY-0039	TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	15 MILES SE OF WRIGHT	2/27/98	3/31/99	TURBINE, STATIONARY	33.3 MW	25 PPM @ 15% O2		OTHER

Source: RBLC 2000.

MAXIMUM	100.0 PPM @ 15% O2
MINIMUM	1.8 PPM @ 15% O2
MEDIAN	20.0 PPM @ 15% O2

Table 5-13. RBLC VOC Summary for Natural Gas Fired CTGs

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate		Emission Limit		Control System Description	Basis
			Issuance	Update							
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	6/23/99	TURBINE, WITH DUCT BURNER	170.0	MW	0.016	LB/MMBTU	EFFICIENT COMBUSTION	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325.0	MMBTU/HR	8.0	LB/HR	NATURAL GAS AS PRIMARY FUEL	LAER
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4	MMBTU/H	1.1	LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4	MMBTU/H	1.1	LB/H	OXIDATION CATALYST	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, SIMPLE CYCLE LM6000 GAS	421.4	MMBTU/H	1.1	LB/H	OXIDATION CATALYST	BACT
CA-0813	SEPCO	RIO LINDA	10/5/94	8/31/99	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920.0	MMBTU/H	3.7	LB/H	OXIDATION CATALYST	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	8/5/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25.0	MW	3.12	LB/H	OXIDATION CATALYST. VOC IS SHOWN AS CH4.	BACT-OTHER
CA-0855	CROCKETT COGENERATION - C&H SUGAR	CROCKETT	10/5/93	4/19/99	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.0	MW	352.6	LB/D	ENGELHARD OXIDATION CATALYST	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	9/28/99	TURBINE, GE, COGENERATION, 48 MW	48.0	MW	0.6	PPMVD @ 15% O2	OXIDATION CATALYST	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246.0	MMBTU/H	16.7	LB/H		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350.0	MMBTU/H	26.7	T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.0	MMBTU/H EACH TURBINE	35.2	T/YR		OTHER
CO-0024	PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	5/1/96	5/19/98	COMBINED CYCLE TURBINES (2), NATURAL	471.0	MW	1.4	PPMVD, SMPL CY	GOOD COMBUSTION CONTROL PRACTICES.	BACT-PSD
CT-0073	PRATT & WHITNEY, UTC	MIDDLETOWN	7/7/89	4/30/90	ENGINE, GAS TURBINE	238.0	MMBTU/H	0.014	LB/MMBTU		BACT-PSD
CT-0139	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24, #1 WITH 2 CHILLERS	2.0	MMCF/H	3.0	LB/H NAT GAS	COMBUSTION CONTROLS	BACT
CT-0140	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24E,#2 WITH 2 CHILLERS	2.0	MMCF/H	3.0	LB/H NAT GAS	COMBUSTION CONTROLS	BACT
FL-0042	ORLANDO UTILITIES COMMISSION	TITUSVILLE	9/1/88	5/14/93	TURBINE, 2 EA	35.0	MW	7.0	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400.0	MW	1.6	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400.0	MW	9.0	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240.0	MW	1.0	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35.0	MW	7.0	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3	MMBTU/H	10.0	PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214.0	MMBTU/H	6.0	LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510.0	MMBTU/H	7.0	PPMVW	GOOD COMBUSTION PRACTICES	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1,032.0	MMBTU/H, NAT GAS	0.003	LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116.0	MW	6.0	PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0	MW EA	0.0055	LB/MMBTU	VOC EMISSION IS BECAUSE OF NO.2 FUEL OIL.	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0	MW EA	0.03	LB/MMBTU	VOC EMISSION IS BECAUSE OF NATURAL GAS.	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338.0	MM BTU/HR TURBINE	3.6	LB/HR COMBINED	COMBUSTION CONTROLS, FUEL SELECTION	BACT
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1,327.0	MMBTU/H	5.1	LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR.	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528.0	MW TOTAL	0.4	PPM @ 15% O2		BACT-PSD
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175.0	MW	3.0	LB/H GAS		BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.0	MW EACH	1.0	PPM	LOW NOX BURNER	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313.0	MM BTU/HR	2.0	LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190.0	MMBTU/HR (EACH)	0.0046	LB/MMBTU	TURBINE DESIGN	OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617.0	MMBTU/HR (EACH)	4.0	PPMDV	TURBINE DESIGN	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257.0	HP	25.0	PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100.0	MW	0	SEE P2	GOOD COMBUSTION PRACTICES	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100.0	MW	0			BACT-PSD
NY-0036	ONEIDA COGENERATION FACILITY	ONEIDA	2/26/90	5/18/90	TURBINE, GE FRAME 6	417.0	MMBTU/H	0.013	LB/MMBTU	COMBUSTION CONTROL	OTHER
NY-0038	EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	5/2/89	5/18/90	TURBINE, GR FRAME 6, 3 EA	416.0	MMBTU/H	0.012	LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
NY-0039	FULTON COGENERATION ASSOCIATES	FULTON	1/29/90	5/18/90	TURBINE, GE LM5000, GAS FIRED	500.0	MMBTU/H	5.0	LB/H	COMBUSTION CONTROL	BACT-PSD
NY-0040	JMC SELKIRK, INC.	SELKIRK	11/21/89	5/18/90	TURBINE, GE FRAME 7, GAS FIRED	80.0	MW	7.0	PPM	COMBUSTION CONTROL	BACT-PSD
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123.0	MMBTU/HR (EACH)	0.0045	LB/MMBTU	OXIDATION CATALYST	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500.0	HP (EACH)	0.1	G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6	KW EACH	105	PPM @ 15% O2	OXIDATION CATALYST	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360.0	MMBTU/HR	4.4	LB/HR	GOOD COMBUSTION PRACTICES	BACT-OTHER
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153.0	MW	4.0	PPM @ 15% O2	OXIDATION CATALYST; OIL LIMIT = 4.4 PPMVD @ 15% O2.	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0	MW	25.0	PPMV@15%O2	GOOD COMBUSTION	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0	MW	5.0	PPMDV	COMBUSTION CONTROLS.	BACT-PSD
RI-0008	PAWTUCKET POWER	PAWTUCKET	1/30/89	3/31/91	TURBINE/DUCT BURNER	533.0	MMBTU/H	19.0	PPM @ 15% O2, GAS		BACT-PSD
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1,360.0	MMBTU/H EACH	5.0	PPM @ 15% O2		BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49.0	MMBTU/H	0.016	LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-OTHER
RI-0018	TIVERTON POWER ASSOCIATES	TIVERTON	2/13/98	2/8/99	COMBUSTION TURBINE, NATURAL GAS	265.0	MW	2.0	PPM @ 15% O2	GOOD COMBUSTION	BACT-PSD
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110.0	MEGAWATTS	10.0	LBS/HR	GOOD COMBUSTION PRACTICES	BACT-PSD
SC-0031	BMW MANUFACTURING CORPORATION	GREER	1/7/94	8/12/96	TURBINE, NAT.GAS FIRED (3 -1 SPARE) AND 2 BOILERS	54.5	MM BTU/HR TURBINES	77.86	LBS/DAY	EACH OF THE 2 BOILER-TURBINE USE A COMMON STACK	LAER
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3	MW (TOTAL POWER)	38.0	TPY	INTERNAL COMBUSTION CONTROLS	BACT
VA-0163	VIRGINIA POWER		9/7/89	4/30/90	TURBINE, GAS	1,308.0	MMBTU/H	2.0	LB/H/UNIT NAT GAS FI		BACT-PSD
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0	MMBTU/H	4.4	LB/H	COMBUSTOR DESIGN & OPERATION, GAS	OTHER
VA-0179	COMMONWEALTH GAS PIPELINE CORPORATION	LOUISA STATION	8/17/90	3/24/95	SOLAR SATURN T-1300,3	14,460.0	CF/H	2.1	LB/H		BACT-PSD
VA-0180	COMMONWEALTH GAS PIPELINE CORPORATION	GOOCHLAND	9/30/90	3/24/95	TURBINES, GAS FIRED, SINGLE CYCLE, 5	14.5	MMBTU/H EACH	0		EQUIPMENT DESIGN & OPERATION	BACT-PSD

Source: RBLC 2000.

MAXIMUM	105.0	PPM @ 15% O2
MINIMUM	0.4	PPM @ 15% O2
MEDIAN	5.5	PPM @ 15% O2

Table 5-14. Florida BACT CO Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
3/7/95	Orange Cogeneration, L.P.	39	30	Good combustion
6/1/95	Panda-Kathleen	75	25	Good combustion
9/28/95	City of Key West	23	20	Good combustion
5/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
9/29/98	Florida Power Corporation Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12.0	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB On)	167	24	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	20	Good combustion
10/8/99	Tampa Electric Company—Polk Power Station	165	15	Good combustion
10/18/99	Vandolah Power Project	170	12	Good combustion
12/28/99	Reliant Energy Osceola	170	10.5	Good combustion
1/13/00	Shady Hills Generating Station	170	12	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB Off)	167	12	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB On)	167	20	Good combustion
2/24/00	Gainesville Regional Utilities	83	25	Good combustion
5/11/00	Calpine Osprey (Draft—DB Off)	170	10	Good combustion
5/11/00	Calpine Osprey (Draft—DB On)	170	17	Good combustion
7/31/00	Gulf Power – Smith Unit 3 (DB On)	170	16	Good combustion

Source: FDEP, 2000.

Table 5-15. Florida BACT VOC Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	VOC Emission Limit (ppmvw)	Control Technology
3/7/95	Orange Cogeneration, L.P.	39	10.0	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	4.0	Good ombustion
9/29/98	Florida Power Corporation Hines Energy Complex	165	7.0	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB Off)	167	1.4	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB On)	167	8	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	5.0	Good combustion
10/8/99	Tampa Electric Company—Polk Power Station	165	1.4	Good combustion
10/18/99	Vandolah Power Project	170	1.4	Good combustion
12/28/99	Reliant Energy Osceola	170	3.7	Good combustion
1/13/00	Shady Hills Generating Station	170	1.4	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB Off)	167	1.4	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB On)	167	4	Good combustion
2/24/00	Gainesville Regional Utilities	83	1.4	Good combustion
5/11/00	Calpine Osprey (Draft—DB Off)	170	2.3	Good combustion
5/11/00	Calpine Osprey (Draft—DB On)	170	4.6	Good combustion
7/31/00	Gulf Power – Smith Unit 3 (DB On)	170	4.0	Good combustion

Source: FDEP, 2000.

The use of oxidation catalysts will, as previously noted, result in excessive H_2SO_4 mist emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTGs and DBs fired with natural gas. Because CO emission rates from CTGs and DBs are inherently low, further reductions through the use of oxidation catalysts will result in only minor improvement in air quality, i.e., well below the defined PSD significant impact levels for CO.

Use of state-of-the-art combustor design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs. These control techniques have been considered by FDEP to represent BACT for CO and VOCs for recent CTG projects.

At baseload operation, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 10.0 and 1.2 ppmvd at 15 percent O_2. At baseload operation with DB firing, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 15.6 and 3.4 ppmvd at 15 percent O_2. At baseload operation with DB firing and with steam power augmentation, the CTG/HRSG CO and VOC exhaust concentrations are projected to be 38.5 and 6.6 ppmvd at 15 percent O_2, respectively; this operating mode will be limited to no more than 1,500 hr/yr. At low load operation (i.e., between 60- and 70-percent load), the CTG/HRSG CO and VOC exhaust concentrations are projected to be 50.0 and 3.0 ppmvd at 15 percent O_2; this operating mode will be limited to no more than 2,880 hr/yr. Table 5-16 summarizes the CO and VOC BACT emission limits proposed for BHEC.

5.5 BACT ANALYSIS FOR NO_X

NO_x emissions from combustion sources consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO_x and prompt NO_x) and conversion of chemically FBN. Essentially all CTG NO_x emissions originate as nitric oxide (NO). NO generated by the CTG combustion process is subsequently further oxidized in the CTG exhaust system or in the atmosphere to the more stable NO_2 molecule.

Table 5-16. Proposed CO and VOC BACT Emission Limits

Emission Source	Proposed CO and VOC BACT Emission Limits ppmvd at 15 percent O_2	lb/hr
Siemens Westinghouse 501F CTGs and DBs (Per CTG/HRSG Unit)		
A. 100-Percent Load Without Steam Power Augmentation, Without DB Firing		
CO	10.0	46.0
VOC	1.2	3.2
B. 100-Percent Load Without Steam Power Augmentation, With DB Firing		
CO	15.6	74.9
VOC	3.4	9.0
C. 100-Percent Load With Steam Power Augmentation, Without DB Firing		
CO	25.0	121.0
VOC	1.2	3.3
D. 100-Percent Load With Steam Power Augmentation, With DB Firing		
CO	38.5	193.2
VOC	6.6	17.7
E. 60- to 70-Percent Load Without Steam Power Augmentation, Without DB Firing		
CO	50.0	155.0
VOC	3.0	5.3

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

Thermal NO_x results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO_x formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO_x increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism. Prompt NO_x is formed near the combustion flame front from the oxidation of intermediate combustion products such as hydrogen cyanide, nitrogen, and NH. Prompt NO_x comprises a small portion of total NO_x in conventional near-stoichiometric CTG combustors but increases under fuel-lean conditions. Prompt NO_x, therefore, is an important consideration with respect to DLN combustors that use lean fuel mixtures. Fuel NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of FBN to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-2). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the N_2 found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

Available technologies for controlling NO_x emissions from CTGs 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 and standard combustor design.
- Water or steam injection and advanced combustor design.
- DLN combustor design.
- XONON™

Postcombustion Exhaust Gas Treatment Systems:

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

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

Water or Steam Injection and Standard Combustor Design

Injection of water or steam into the primary combustion zone 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. Water or steam injection will not reduce the formation of fuel NO_x.

The maximum amount of steam or water that can be injected depends on the CTG combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO_x emissions also depends on turbine combustor design. 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 effect safe, efficient, and reliable operation of the turbine.

The use of water or steam injection and standard turbine combustor design can generally achieve NO_x exhaust concentrations of 42 and 65 ppmvd for gas and oil firing, respectively.

Water or Steam Injection and Advanced Combustor Design

Water or steam injection functions in the same manner for advanced combustor designs as described previously for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO_x and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO_x exhaust concentrations of 25 and 42 ppmvd for gas and oil firing, respectively.

Dry Low-NO_x Combustor Design

A number of turbine vendors have developed DLN combustors that premix turbine fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. For this reason, the peak and average flame temperature are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical DLN combustor incorporates fuel staging using several operating modes as follows:

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.
- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 50 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load

until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.

- Secondary Mode (Transfer to Premix)—At 70-percent load, all fuel is supplied to second stage.
- Premix Mode—Fuel is provided to both stages with approximately 80 percent furnished to the first stage at turbine loads from 70 to 100 percent. Flame is present in the second stage only.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. During oil firing, wet injection is employed to control NO_x emissions.

In addition to lean premixed combustion, CTG DLN combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO_x formation. All CTGs cool the high-temperature CTG exhaust gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the CTG turbine. By adding additional dilution air, the hot CTG exhaust gases are rapidly cooled to temperatures below those needed for NO_x formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO_x is reduced because the CTG combustion gases are at a higher temperature for a shorter period of time.

Current DLN combustor technology can typically achieve a NO_x exhaust concentration of 25 ppmvd or less using natural gas fuel.

XONON™

The XONON™ Cool Combustion technology, being developed for CTGs by Catalytica Combustion Systems, Inc. (CCSI), 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 pre-combustor. 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 pre-combustor and the flameless combustor catalyst module. Information provided by CCSI indicates that the XONON™ Cool Combustion technology is capable of achieving CTG NO_x exhaust concentrations of 2.5 ppmvd at 15 percent O_2.

Commercial operation of the XONON™ Cool Combustion technology is limited to one small (1.5 MW) base load, 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.

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

The CTGs planned for the BHEC are Siemens Westinghouse 501F units. The XONON™ Cool Combustion technology is not commercially available for these units. As noted above, Siemens Westinghouse is not a current participant in the XONON™ Cool Combustion technology development program. 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 an available control technology for the Siemens Westinghouse 501F CTGs.

Selective Non-Catalytic Reduction

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

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

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

The NO_xOUT process is similar with the exception that urea is used in place of NH_3. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted NH_3 to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1) resulting in a reduction in NO_x emissions. Reaction (2) will dominate at temperatures above approximately 2,000°F, causing an increase in NO_x emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

Non-Selective Catalytic Reduction

The NSCR process utilizes a platinum/rhodium catalyst to reduce NO_x to nitrogen and water vapor under fuel-rich (less than 3 percent O_2) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

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

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

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

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

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), NH_3/NO_x molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO_x removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO_x with NH_3 theoretically requires a 1:1 molar ratio. NH_3/NO_x molar ratios greater than 1:1 are necessary to achieve high-NO_x removal efficiencies due to imperfect mixing and other reaction limitations. However, NH_3/NO_x molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted NH_3 (ammonia slip) emissions.

As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Specially formulated, high-temperature zeolite catalysts have recently been developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. NO_x removal efficiencies for SCR systems typically range from 70 to 90 percent.

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

<u>SCONO$_x$™</u>

SCONO$_x$™ is a NO_x and CO control system offered by ABB Alstom Power Environmental Segment (AAP) under an exclusive license agreement with Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc.

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

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

$$NO + \tfrac{1}{2} O_2 \rightarrow NO_2 \qquad (6)$$

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

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

As shown in reaction (7), the potassium carbonate catalyst coating reacts with NO_2 to form potassium nitrites and nitrates. Prior to saturation of the potassium carbonate coating, the catalyst must be regenerated. This regeneration is accomplished by passing a dilute hydrogen-reducing gas across the surface of the catalyst in the absence of O_2. Hydrogen in the reducing gas reacts with the nitrites and nitrates to form water and elemental nitrogen. CO_2 in the regeneration gas reacts with potassium nitrites and nitrates to form potassium carbonate; this compound is the catalyst absorber coating present on the surface of the catalyst at the start of the oxidation/absorption cycle. The SCONO$_x$™ regeneration cycle reaction is:

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

Water vapor and elemental nitrogen are released to the atmosphere as part of the CTG/HRSG exhaust stream. Following regeneration, the SCONO$_x$™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. There is no net gain or loss of potassium carbonate after both the oxidation/absorption and regeneration cycles have been completed.

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 80 percent of the catalyst sections will be in the oxidation/absorption cycle, while 20 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 8 minutes.

The SCONO$_x$™ 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 SCONO$_x$™ system uses an inert gas generator for the production of hydrogen and CO_2. The regeneration gas is diluted to under 4 percent hydrogen using steam as a carrier gas; the typical system is designed for 2 percent hydrogen. The regeneration gas reaction is:

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

For installations above 450°F, the SCONO$_x$™ 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 SCONO$_x$™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the SCONO$_x$™ catalyst. The reformer catalyst works to partially reform the methane gas to hydrogen (2 percent by volume) to be used in the regeneration of the SCONO$_x$™ and SCOSO$_x$™ catalysts. The reformer converts methane to hydrogen by the steam reforming reaction as shown by the following equation:

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

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

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

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

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

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

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

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

(below 500°F)

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

(above 500°F)

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

Utility materials needed for the operation of the $SCONO_x$™/$SCOSO_x$™ 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 $SCONO_x$™ control system is limited to several small CC power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by GLET partner Sunlaw Energy Corporation, equipped with water injection to control NO_x emissions to approximately 25 ppmvd. The low temperature $SCONO_x$™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO_x exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO_x removal efficiency. A high temperature application of $SCONO_x$™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW Solar CTG located at the Genetics Institute in Massachusetts. Following a 1 year scale-up developmental program, on December 1, 1999, AAP announced the commercial availability of the $SCONO_x$™ for large-scale natural gas-fired CTGs, particularly F-Class units. Although considered commercially available for large natural gas-fired CTGs, there are currently no CTGs larger than 5-MW that have demonstrated successful application of the high temperature $SCONO_x$™ control technology.

Technical Feasibility

All of the combustion process modification technologies mentioned (water or steam injection and standard combustor design, water or steam injection and advanced combustor design, and DLN combustor design) would be feasible for the BHEC CTG/HRSG units. Of the postcombustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that found in CTG exhaust gas streams (approximately 1,100°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3-percent O_2) environment. Due to high excess air rates, the O_2 content of combustion turbine exhaust gases is typically 13 percent.

The SCONO$_x$™ control technology is considered technically feasible due to its commercial availability. However, as noted above, there are currently no CTGs larger than 5 MW that have demonstrated successful application of the high temperature SCONO$_x$™ control technology. The CTGs planned for the BHEC, Siemens Westinghouse 501F units, have a nominal generation capacity of 170-MW. Accordingly, the BHEC CTGs are 34 times larger than the nominal 5-MW Solar CTG used at the Genetics Massachusetts facility. The Sunlaw Energy Corporation SCONO$_x$™ installation was a retrofit project; i.e., the SCONO$_x$™ system is located downstream of the HRSG. At this location, the control system operates at a lower temperature range (300 to 350°F) than a system installed within the HRSG (i.e., at a temperature range of 600 to 700°F). Technical problems associated with scale-up of the SCONO$_x$™ technology under higher temperatures remain undemonstrated under actual operating conditions. Additional concerns with SCONO$_x$™ 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. There are no SCONO$_x$™ control systems installed as BACT in ozone attainment areas.

For natural gas firing, use of advanced DLN combustor technology will achieve NO_x emission rates comparable to or less than wet injection based on CTG vendor data. Accordingly, the BACT analysis for NO_x for the BHEC CTG/HRSGs was confined to advanced DLN combustors, and the application of postcombustion SCR and SCONO$_x$™ control technologies. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

The use of advanced DLN combustor technology will not have a significant adverse impact on CTG heat rate.

The installation of SCR technology will cause an increase in back pressure on the CTG due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for the BHEC CTG is projected to have a pressure drop across the catalyst bed of approximately 2.0 inches of water. This pressure drop will result in a 0.4-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 23,827,200 kwh (81,302 MMBtu) per year at baseload (170 MW per CTG) operation and 8,760 hr/yr operation for the four CTGs. This energy penalty is equivalent to the use of 77.43 million ft^3 of natural gas annually based on a nominal natural gas heating value of 1,050 Btu/ft^3. The lost power generation energy penalty, based on a power cost of $0.037/kwh, is $881,600 per year for all four CTGs.

The installation of $SCONO_x$™ technology will also cause an increase in back pressure on the CTG due to the pressure drop across the catalyst bed. A $SCONO_x$™ control system for the BHEC CTG is projected to have a pressure drop across the catalyst bed of approximately 5.0 inches of water. This pressure drop will result in a 1.0-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 59,568,000 kwh (203,254 MMBtu) per year at baseload (170 MW per CTG) operation and 8,760 hr/yr operation for the four CTGs. This energy penalty is equivalent to the use of 193.58 million ft^3 of natural gas annually based on a nominal natural gas heating value of 1,050 Btu/ft^3. The lost power generation energy penalty, based on a power cost of $0.037/kwh, is $2,204,016 per year.

There are no significant adverse environmental effects due to the use of advanced DLN combustor or $SCONO_x$™ technology. SCR technology will result in collateral emissions of ammonia (i.e., "ammonia slip") and ammonium bisulfate and ammonium sulfate particulate matter.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced DLN combustor technology and baseline technology with the addition of SCR and SCONO$_x$™ controls. The base case BHEC annual NO$_x$ emission rate (i.e., for all four CTG/HRSG units) is 3,718.5 tpy based on CTG baseload operation for 5,880 hr/yr at 59°F, and CTG baseload operation for 2,880 hr/yr at 95°F with CTG inlet air evaporative cooling, steam power augmentation, and HRSG DB firing. The SCR controlled annual NO$_x$ emission rate, based on an 86.4 percent control efficiency, is 563.3 tpy. The SCONO$_x$™ controlled annual NO$_x$ emission rate, based on an 92.2 percent control efficiency, is 289.1 tpy. Base case and controlled NO$_x$ emission rates are summarized in Table 5-20. Baseline technology is expected to achieve a NO$_x$ exhaust concentration of 25.0 at 15-percent O_2. SCR and SCONO$_x$™ technology were premised to achieve NO$_x$ concentrations of 3.5 and 2.0 ppmvd at 15-percent O_2, respectively.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 5-1 and BHEC specific economic factors provided in Table 5-8. Tables 5-17 and 5-18 summarize specific capital and annual operating costs for the SCR control system, respectively. Tables 5-19 and 5-20 summarize specific capital and annual operating costs for the SCONO$_x$™ control system, respectively, based on Alstom data and a Department of Energy (DOE) study (DOE, 1999).

Average cost effectiveness for the application of SCR and SCONO$_x$™ technology to the BHEC CTG was determined to be \$1,978 and \$9,982 per ton of NO$_x$ removed, respectively. Incremental cost effectiveness of SCONO$_x$™ technology was determined to be \$113,012 per ton of NO$_x$ removed. The control cost for SCR is considered economically reasonable. However, the incremental control cost for SCONO$_x$™ is substantially higher than previously considered reasonable by the FDEP. Table 5-21 summarizes results of the NO$_x$ BACT analysis.

Table 5-17. Capital Costs for SCR Catalyst System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	7,100,000	A
Sales tax	426,000	0.06 x A
Instrumentation	710,000	0.10 x A
Freight	355,000	0.05 x A
HRSG Modifications	740,000	
Subtotal Purchased Equipment	**9,331,000**	B
Installation		
Foundations and supports	746,480	0.08 x B
Handling and erection	1,306,340	0.14 x B
Electrical	373,240	0.04 x B
Piping	186,620	0.02 x B
Insulation for ductwork	93,310	0.01 x B
Painting	93,310	0.01 x B
Subtotal Installation Cost	**2,799,300**	
Total Direct Costs (TDC)	**12,130,300**	
Indirect Costs		
Engineering	933,100	0.10 x B
Construction and field expenses	466,550	0.05 x B
Contractor fees	933,100	0.10 x B
Startup	186,620	0.02 x B
Performance test	93,310	0.01 x B
Contingency	279,930	0.03 x B
Total Indirect Costs (TIC)	**2,892,610**	
TOTAL CAPITAL INVESTMENT (TCI)	**15,022,910**	TDC + TIC

Source: ECT, 2000.

Table 5-18. Annual Operating Costs for SCR Catalyst System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Operator Labor	63,000	
Maintenance Labor and Material	109,600	
Subtotal Labor and Maintenance Costs	**172,600**	C
Catalyst costs		
Replacement (materials, labor, and disposal)	5,683,200	
Annualized Catalyst Costs	**2,285,300**	3-yr replacement
Aqueous ammonia costs	760,000	$113/ton
Electricity costs	285,200	
Energy Penalties		
Turbine backpressure	881,600	0.4 % penalty
Emission fee credit	(79,554)	$25/ton
Total Direct Costs (TDC)	**4,305,146**	
Indirect Costs		
Overhead	103,600	0.60 x C
Administrative charges	300,500	0.02 x TCI
Property taxes	150,200	0.01 x TCI
Insurance	150,200	0.01 x TCI
Capital recovery	1,286,200	15 yrs @ 10.0%
Total Indirect Costs (TIC)	**1,990,700**	
TOTAL ANNUAL COST (TAC)	**6,295,846**	TDC + TIC

Sources: Calpine, 2000.
ECT, 2000.

Table 5-19. Capital Costs for $SCONO_x$™ System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	65,600,000	A
Sales tax	3,963,000	0.06 x A
Instrumentation	0	Included
Freight	3,280,000	0.05 x A
HRSG Modifications	740,000	
Subtotal Purchased Equipment	**73,556,000**	B
Installation		
Foundations and supports	5,884,480	0.08 x B
Handling and erection	10,297,840	0.14 x B
Electrical	2,942,240	0.04 x B
Piping	1,471,120	0.02 x B
Insulation for ductwork	735,560	0.01 x B
Painting	735,560	0.01 x B
Subtotal Installation Cost	**22,066,800**	
Total Direct Costs (TDC)	**95,622,800**	
Indirect Costs		
Engineering	7,355,600	0.10 x B
Construction and field expenses	3,677,800	0.05 x B
Contractor fees	7,355,600	0.10 x B
Startup	1,471,120	0.02 x B
Performance test	735,560	0.01 x B
Contingency	2,206,680	0.03 x B
Total Indirect Costs (TIC)	**22,802,360**	
TOTAL CAPITAL INVESTMENT (TCI)	**118,425,160**	TDC + TCI

Source: ECT, 2000.

Table 5-20. Annual Operating Costs for $SCONO_x$™ System, Four CTG/HRSGs

Item	Dollars	OAQPS Factor
Direct Costs		
Operator Labor	63,000	
Maintenance Labor and Material	109,600	
Subtotal Labor and Maintenance Costs	**172,600**	C
Catalyst costs		
Replacement (materials, labor, and disposal)	36,510,000	
Metal Recovery (credit)	(10,824,000)	
Annualized Catalyst Costs	**10,328,700**	3-yr replacement
Guard Bed		
Catalyst washing	800,000	
Natural gas costs (H_2 reforming)	323,573	
Electricity costs	132,241	
Steam costs (H_2 carrier)	3,323,894	
Energy Penalties		
Turbine backpressure	2,204,000	1.0 % penalty
Emission fee credit	(85,734)	$25/ton
Total Direct Costs (TDC)	**17,199,274**	
Indirect Costs		
Overhead	103,600	0.60 x C
Administrative charges	2,368,500	0.02 x TCI
Property taxes	1,184,300	0.01 x TCI
Insurance	1,184,300	0.01 x TCI
Capital recovery	12,192,800	15 yrs @ 10.0%
Total Indirect Costs (TIC)	**17,033,500**	
TOTAL ANNUAL COST (TAC)	**34,232,774**	TDC + TIC

Table 5-21. Summary of NO_x BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Emission Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Economic Impacts: Total Annualized Cost ($/yr)	Economic Impacts: Average Cost Effectiveness ($/ton)	Economic Impacts: Incremental Cost Effectiveness ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Environmental Impacts: Adverse Envir. Impact (Y/N)
SCONOx™ [2.0 ppmvd at 15% O_2]	66.0	289.1	3,429.4	56,234,080	34,232,774	9,982	113,012	203,254	N	N
SCR [3.5 ppmvd at 15% O_2]	122.4	536.3	3,182.2	15,022,910	6,295,846	1,978	N/A	81,302	N	N
Base Case [25 ppmvd at 15% O_2]	849.0	3,718.5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Four Siemens Westinghouse 501F CTG/HRSG units.

Sources: Calpine, 2000.
ECT, 2000.
Engelhard, 2000.
Siemens Westinghouse, 2000.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

BACT NO_x limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-22. Recent Florida BACT determinations for natural gas-fired CTGs are shown in Table 5-23.

Under all operating scenarios, the maximum NO_x exhaust concentration and hourly mass emission rate from the CTG/HRSG units will be 3.5 ppmvd and 31.9 lb/hr, respectively, based on the application of DLN combustors, low-NOx burners, and SCR. Table 5-24 summarizes the NO_x BACT emission limits proposed for BHEC. NO_x emission rates proposed as BACT for the BHEC CTG/HRSG units are consistent with recent FDEP and EPA Region 4 BACT determinations.

5.6 BACT ANALYSIS FOR SO_2 AND H_2SO_4 MIST

5.6.1 POTENTIAL CONTROL TECHNOLOGIES

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

Fuel Treatment

Fuel treatment technologies are applied to gaseous, liquid, and solid fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas and fuel oils containing sulfur compounds (e.g., hydrogen sulfide), 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.

Table 5-22. RBLC NO_x Summary for Natural Gas Fired CTGs (Page 1 of 3)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AK-0021	ARCO ALASKA, INC.	PRUDHOE BAY	10/16/89	3/24/95	TURBINES, GAS FIRED, 3	5,400.0 HP/TURBINE	125 PPM @ 15% O2	DRY CONTROL	BACT-PSD
AL-0045	SHELL OFFSHORE, INC.	CODEN	10/25/89	2/28/90	TURBINE, GAS FIRED	5,000.0 HP	42 PPM	H2O INJECTION	BACT-PSD
AL-0074	FLORIDA GAS TRANSMISSION COMPANY	MOBILE	8/5/93	5/12/94	TURBINE, NATURAL GAS	12,600.0 BHP	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DRY LOW NOX COMBUSTION	BACT-PSD
AL-0089	SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESSOR STAT	SELMA	12/4/96	12/18/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE	0.0	53 LB/HR		BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568.0 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)	FUEL OIL SULFUR CONTENT < =0.05% BY WEIGHT DRY	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL MS3002G NATURAL GAS FIRED TURBINE	9,160.0 HP	53 LB/HR		BACT-PSD
AL-0110	SOUTHERN NATURAL GAS	WARD	3/4/98	4/24/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9,160.0 HP	53 LB/HR		BACT-PSD
AL-0115	ALABAMA POWER COMPANY	MCINTOSH	12/17/97	4/24/98	COMBUSTION TURBINE W/ DUCT BURNER (COMBINED CYCLE)	100.0 MW	15 PPM	DRY LOW NOX BURNERS	BACT-PSD
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)	0.0	0.07 LBS/MMBTU COMBINED	DRY LOW NOX BURNER ON TURBINE AND LOW NOX BURNER	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	6/23/99	TURBINE, WITH DUCT BURNER	170.0 MW	0.013 LB/MMBTU	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5,500.0 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5,500.0 HP	84.9 PPM @ 15% O2	LEAN BURN	NSPS
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5,500.0 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5,500.0 HP	85.0999 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	NSPS
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000.0 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12,000.0 HP	225 PPM @ 15% O2	LEAN BURN	BACT-PSD
CA-0318	O'BRIAN CALIFORNIA COGEN II, LIMITED		1/4/90	5/18/90	TURBINE, GAS GENERATOR SET W/DUCT BURNER	49.5 MW	350.4 LB/D	SCR, DRY TYPE	LAER
CA-0320	BADGER CREEK LIMITED		10/30/89	5/18/90	TURBINE, GAS COGENERATION	457.8 MMBTU/H	0.0135 LB/MMBTU	SCR, STEAM INJECTION	BACT-PSD
CA-0336	CITY OF ANAHEIM GAS TURBINE PROJECT		9/15/89	5/18/90	TURBINE, GAS, GE PGLM 5000	442.0 MMBTU/H	90 LB/D	SCR, STEAM INJECTION, CO REACTOR	BACT-PSD
CA-0399	SARGENT CANYON COGENERATION COMPANY		11/19/90	3/24/95	TURBINE, GAS W/ HEAT RECOVERY STEAM GENERATOR	42.5 MW	240 LB/D	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
CA-0400	SALINAS RIVER COGENERATION COMPANY		11/19/90	3/24/95	TURBINE,GAS, W/ HEAT RECOVERY STEAM GENERATOR	43.2 MW	240 LB/D	TURBINE DRY LOW NOX COMBUST SYS W/ SCR CNTRL SYS	BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.6 MMBTU/H	8 PPMVD @ 15% O2	HIGH TEMPERATURE SELECTIVE CATALYTIC REDUCTION	BACT-PSD
CA-0437	KINGSBURG ENERGY SYSTEMS		9/28/89	8/3/93	TURBINE, NATURAL GAS FIRED, DUCT BURNER	34.5 MW	6 PPM @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
CA-0441	GRANITE ROAD LIMITED		5/6/91	8/3/93	TURBINE, GAS, ELECTRIC GENERATION	460.9 MMBTU/H*	3.5 PPMVD @ 15% O2	SCR, STEAM INJECTION	BACT-PSD
CA-0463	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	5/31/92	TURBINE, GAS FIRED, SOLAR MODEL H	5,500.0 HP	8 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	BACT-PSD
CA-0544	GOAL LINE, LP ICEFLOE	ESCONDIDO	11/3/92	8/4/94	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386.0 MMBTU/HR	5 PPMVD @ 15% OXYGEN	WATER INJECTION & SCR W/ AUTOMATIC AMMONIA INJECT	BACT-OTHER
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)	0.0	9 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR), WATER INJECTN	BACT-OTHER
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325.0 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX BURNERS	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT	0.0	0.109 LB/MMBTU	LOW-NOX COMBUSTOR	LAER
CA-0794	CALRESOURCES LLC		1/10/97	3/16/98	SOLAR MODEL 1100 SATURN GAS TURBINE	13.6 MMBTU/HR	69 PPMVD @15% O2	NO CONTROL	LAER
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	3 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, GAS, COMBINED CYCLE LM6000	421.4 MMBTU/H	5 PPM @ 15% O2	SELECTIVE CATAYTIC REDUCTION AND WATER INJECTION	BACT
CA-0810	SACRAMENTO COGENERATION AUTHORITY P&G	SACRAMENTO	8/19/94	8/31/99	TURBINE, SIMPLE CYCLE LM6000 GAS	421.4 MMBTU/H	5 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION	BACT
CA-0811	SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	8/19/94	11/24/99	TURBINE GAS, COMBINE CYCLE SIEMENS V84.2	1,257.0 MMBTU/H	3 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX C	BACT
CA-0813	SEPCO	RIO LINDA	10/5/94	8/31/99	TURBINE, GAS COMBINED CYCLE GE MODEL 7	920.0 MMBTU/H	2.6 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX C	BACT
CA-0845	SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	8/19/94	4/13/99	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2	1,257.0 MMBTU/H	3 PPMVD @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX CO	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING AUT	ELK GROVE	7/23/93	11/23/99	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450.0 MMBTU/H	5 PPMVD @ 15% O2	SELECTIVE CATALYTIC REDUCTION AND WATER INJECTION ,	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING AUT	ELK GROVE	7/23/93	11/23/99	TURBINE, GAS, SIMPLE CYCLE, GE LM6000	450.0 MMBTU/H	5 PPMVD @ 15% O2	SELECTIVE CATAYLTIC REDUCTION AND WATER INJECTION	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	8/6/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25.0 MW	96.9599 LB/D	WATER INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT-OTHER
CA-0855	CROCKETT COGENERATION - C&H SUGAR	CROCKETT	10/5/93	4/19/99	TURBINE, GAS, GENERAL ELECTRIC MODEL PG7221(FA)	240.0 MW	5 PPMVD @ 15% O2	DRY LOW-NOX COMBUSTERS AND A MITSUBISHI HEAVY I	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	9/28/99	TURBINE, GE, COGENERATION, 48 MW	48.0 MW	3.6 PPMVD @ 15% O2	STEAM INJECTION AND SELECTIVE CATALYTIC REDUCTION	BACT-OTHER
CA-0863	SUNLAW COGEN. (FEDERAL COLD STORAGE COGENERATION)	VERNON	1/15/94	4/19/99	TURBINE, NATURAL GAS FIRED, COMBINED CYCLE AND COG	28.0 MW	186817 LB/YR	WATER INJECTION AND SCONOX (MOD 2) CATALYST SY	BACT-OTHER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246.0 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX TECH.	BACT-PSD
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350.0 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX BURNER	BACT-PSD
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385.0 MMBTU/H EACH TU	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33.0 MW	9 PPM @ 15% O2	SCR	OTHER
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #1, GE FRAME 6	33.0 MW	25 PPM @ 15% O2	WATER INJECTION	OTHER
CO-0021	NORTHWEST PIPELINE CORPORATION	LA PLATA B" STATION"	5/29/92	7/20/94	TURBINE, SOLAR TAURUS	45.0 MMBTU/HR	95 PPMVD (UNTIL 11/98)	DRY LOW NOX COMBUSTOR (BY 11/01/98)	BACT-PSD
CO-0023	PHOENIX POWER PARTNERS	GREELEY	5/11/93	3/24/95	TURBINE (NATURAL GAS)	311.0 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT-OTHER
CO-0024	PUBLIC SERVICE OF COLO.-FORT ST VRAIN	PLATTEVILLE	5/1/96	5/19/98	COMBINED CYCLE TURBINES (2), NATURAL	471.0 MW	15 PPMVD, SMPL CY	DRY LOW NOX COMBUSTION SYSTEMS FOR TURBINES AND	BACT-PSD
CO-0025	COLORADO SPRINGS UTILITIES-NIXON POWER PLANT	FOUNTAIN	6/30/98	5/19/98	SIMPLE CYCLE TURBINE, NATURAL GAS	1,122.0 MM BTU/HR	25 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT-PSD
CO-0026	WESTPLAINS ENERGY	PUEBLO	6/14/96	2/11/99	SIMPLE CYCLE TURBINE, NATURAL GAS	218.5 MW	15 PPM @ 15% O2 (@>75%)	DRY LOW NOX COMBUSTION SYSTEM (DLN). COMMITMENT	BACT-PSD
CO-0027	COLO. POWER PARTNERS- BRUSH COGEN FAC	BRUSH	3/27/97	5/19/98	COGEN TURBINES W/ DUCT BURNERS & BOILERS	385.0 MM BTU/HR	42 PPM @ 15% O2	LOW NOX COMBUSTION RETROFIT AND WATER INJECTION	BACT-PSD
CO-0037	COLORADO SPRINGS UTILITIES	FOUNTAIN	1/4/99	4/19/99	TURBINE, COMBINE, NATURAL GAS FIRED	30.0 MW EACH	15 PPMVD ABOVE 70% LOAD	POLLUTION PREVENTION BUILT INTO EQUIPMENT.	BACT-PSD
CT-0022	O'BRIEN COGENERATION	HARTFORD	8/8/88	4/30/90	TURBINE, GAS FIRED	499.9 MMBTU/H	39 PPM @ 15% O2 GAS	WATER INJECTION	BACT-PSD
CT-0022	O'BRIEN COGENERATION	HARTFORD	8/8/88	4/30/90	TURBINE, GAS FIRED	499.9 MMBTU/H	39 PPM @ 15% O2 GAS	WATER INJECTION	BACT-PSD
CT-0025	CAPITOL DISTRICT ENERGY CENTER	HARTFORD	10/23/89	4/30/90	ENGINE, GAS TURBINE	738.8 MMBTU/H	42 PPM @ 15% O2, GAS	STEAM INJECTION	BACT-PSD
CT-0027	DOWNTOWN COGENERATION ASSOC.	HARTFORD	8/19/87	4/30/90	TURBINE, GAS W/DUCT BURNER	71.9 MMBTU/H	42 PPM @ 15% O2 GAS	WATER INJECTION	BACT-PSD
CT-0031	CCF-1	HARTFORD	5/18/88	4/30/90	TURBINE, ALLISON, 2 EA	110.0 MMBTU/H GAS FIRE	36 PPM @ 15% O2 GAS	WATER INJECTION	BACT-PSD
CT-0073	PRATT & WHITNEY, UTC	MIDDLETOWN	7/7/89	4/30/90	ENGINE, GAS TURBINE	238.0 MMBTU/H	0.791 LB/MMBTU		BACT-PSD
CT-0130	BRIDGEPORT ENERGY, LLC	BRIDGEPORT	6/29/98	1/21/99	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260.0 MW/HRSG PER TUR	6 PPM NAT. GAS	DRY LOW NOX BURNER WITH SCR	BACT-PSD
CT-0139	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24, #1 WITH 2 CHILLERS	2.0 MMCF/H	2 PPMV @ 15% O2 GAS	SCR WITH AMMONIA INJECTION	LAER
CT-0140	PDC EL PASO MILFORD LLC	MILFORD	4/16/99	6/17/99	TURBINE, COMBUSTION, ABB GT-24E,#2 WITH 2 CHILLERS	2.0 MMCF/H	2 PPMV @ 15% O2 GAS	SCR WITH AMMONIA INJECTION	LAER
DE-0008	DELMARVA POWER	WILMINGTON	9/27/90	3/24/95	TURBINE, COMBUSTION	100.0 MW	0.1 LB/MMBTU	LOW NOX BURNER	BACT-PSD
FL-0042	ORLANDO UTILITIES COMMISSION	TITUSVILLE	9/1/88	5/14/93	TURBINE, 2 EA	35.0 MW	42 PPM @ 15% O2, GAS	STEAM INJECTION	BACT-PSD
FL-0043	TROPICANA PRODUCTS, INC.	BRADENTON	5/30/89	5/14/93	TURBINE, GAS	45.4 MW	42 PPM @ 15% O2	STEAM INJECTION	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80.0 MW	25 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400.0 MW	25 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400.0 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING ST	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240.0 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42.0 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35.0 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0059	SEMINOLE FERTILIZER CORPORATION	BARTOW	3/17/91	5/14/93	TURBINE, GAS	26.0 MW	9 PPM @ 15% O2	SCR	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	TURBINE, GAS	1,614.8 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0074	FLORIDA GAS TRANSMISSION	PERRY	9/27/93	4/11/94	TURBINE, GAS	131.6 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	2/21/00	TURBINE, NATURAL GAS	869.0 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	2/21/00	TURBINE, NATURAL GAS	367.0 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1,214.0 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1,510.0 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74.0 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS	BACT-PSD

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75.0 MW	15 PPM @ 15% O2	DRY LOW NOX BURNER	BACT-PSD
FL-0109	KEY WEST CITY ELECTRIC SYSTEM	KEY WEST	9/28/95	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23.0 MW	75 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0116	SANTA ROSA ENERGY LLC	NORTHBROOK	12/4/98	4/16/99	TURBINE, COMBUSTION, NATURAL GAS	241.0 MW	9.8 PPM@15%O2 DB ON	DRY LOW NOX BURNER	BACT-PSD
FL-0123	DUKE ENERGY NEW SOMYRNA BEACH POWER CO. LP	CHARLOTTE NC (HEADQUART	10/15/99	11/11/99	TURBINE-GAS, COMBINED CYCLE	500.0 MW (2 UNITS)	9 PPM @ 15% O2	DLN GE DLN2.6 BURNERS	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1,032.0 MMBTU/H, NAT GA	25 PPM @ 15% O2	MAX WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1,817.0 M BTU/HR	25 PPM @ 15% O2	MAXIMUM WATER INJECTION	BACT-PSD
GA-0056	GEORGIA POWER COMPANY, ROBINS TURBINE PROJECT	ROBINS AIR FORCE BASE	5/13/94	3/24/95	TURBINE, COMBUSTION, NATURAL GAS	80.0 MW	25 PPM	WATER INJECTION, FUEL SPEC: NATURAL GAS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116.0 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	15 PPMVD @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF NA	BACT-PSD
GA-0069	TENUSKA GEORGIA PARTNERS, L.P.	FRANKLIN	12/18/98	6/23/99	TURBINE, COMBUSTION, SIMPLE CYCLE, 6	160.0 MW EA	42 PPMVD @ 15% O2	USING 15% EXCESS AIR. NOX EMISSION IS BECAUSE OF FU	BACT-PSD
IL-0039	AMOCO RESEARCH CENTER	NAPERVILLE	32885	6/7/93	TURBINE, NAT GAS FIRED	96.0 MMBTU/H	49 PPM @ 15% O2	WATER INJECTION	BACT-PSD
LA-0063	OXY NGL, INC.	JOHNSON BAYOU	11/14/89	1/31/90	TURBINE, SOLAR GAS	13.5 MMBTU/H	3.7 LB/H	COMBUSTION DESIGN	BACT-PSD
LA-0063	OXY NGL, INC.	JOHNSON BAYOU	11/14/89	1/31/90	TURBINE, CENTAUR GAS, 4	29.4 MMBTU/H	21.6 LB/H	COMBUSTION DESIGN	BACT-PSD
LA-0063	OXY NGL, INC.	JOHNSON BAYOU	11/14/89	1/31/90	TURBINE, SOLAR GAS	29.4 MMBTU/H	21.6 LB/H	COMBUSTION DESIGN	BACT-PSD
LA-0067	CHEM PROCESS INCORPORATED	NORCO	9/30/90	3/24/95	TURBINE, NATURAL GAS	218.9 MMBTU/H	55 PPM @ 15% O2	LOW NOX BURNERS	OTHER
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	40 PPM @ 15% O2	H2O INJECT 0.67 LB/LB	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338.0 MM BTU/HR TURBIN	25 PPMV 15% O2 TURBINE	DRY LOW NOX COMBUSTOR/COMBUSTION CONTROL	BACT
LA-0089	FORMOSA PLASTICS CORPORATION, LOUISIANA	BATON ROUGE	3/2/95	4/17/95	TURBINE/HRSG, GAS COGENERATION	450.0 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CONTROI	LAER
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1,123.0 MM BTU/HR	25 PPMV-CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION	BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450.0 MM BTU/HR	9 PPMV	DRY LOW NOX BURNER/COMBUSTION DESIGN AND CC	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1,313.0 MM BTU/HR	25 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
LA-0112	AIR LIQUIDE AMERICA CORPORATION	GEISMAR	2/13/98	1/20/99	TURBINE GAS, GE, 7ME 7	966.0 MMBTU/H	9 PPMV	DRY LOW NOX TO LIMIT NOX EMISSION TO 9PPMV	BACT-PSD
LA-0113	BASF CORPORATION	GEISMAR	12/30/97	1/21/99	TURBINE, COGEN UNIT 2, GE FRAME 6	42.4 MW	8 PPMV NAT. GAS	STEAM INJECTION AND SCR TO LIMIT NOX TO 8 PPM FOR N/	BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412.0 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1,327.0 MMBTU/H	17.12 LB/H	DRY LOW NOX COMBUSTION TECHNOLOGY WITH SCR ADD-I	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90.0 MW	199 LB/HR	WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	TURBINE, 84 MW NATURAL GAS FIRED ELECTRIC	84.0 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/26/90	7/20/94	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105.0 MW	77 PPM @ 15% O2	DRY PREMIX AND WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140.0 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	TURBINE, 124 MW NATURAL GAS FIRED	125.0 MW	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
ME-0014	RUMFORD POWER ASSOCIATES	RUMFORD	5/1/98	2/10/99	TURBINE GENERATOR, COMBUSTION, NATURAL GAS	1,906.0 MMBTU/H	3.5 PPM @ 15% O2	SCR AMMONIA INJECTION SYSTEM AND CATALYTIC REACT(	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528.0 MW TOTAL	2.5 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION AND DRY LOW NOX BUR	LAER
ME-0019	CHAMPION INTERNATL CORP. & CHAMP. CLEAN ENERGY	BUCKSPORT	9/14/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS	175.0 MW	9 PPMVD @15% O2 GAS	DRY LOW NOX BURNER 1 OPTION IS C(	BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170.0 MW EACH	3.5 PPM @15% O2	SELECTIVE CATALYTIC REDUCTION	BACT-PSD
MI-0206	KALAMAZOO POWER LIMITED	COMSTOCK	12/3/91	3/23/94	TURBINE, GAS-FIRED, 2, W/ WASTE HEAT BOILERS	1,805.9 MMBTU/H	15 PPMV	DRY LOW NOX TURBINES	BACT-PSD
MI-0244	WYANDOTTE ENERGY	WYANDOTTE	2/8/99	4/19/99	TURBINE, COMBINED CYCLE, POWER PLANT	500.0 MW	4.5 PPM	SCR	BACT
MS-0030	SOUTHERN NATURAL GAS COMPANY	BAY SPRINGS	12/17/96	3/24/97	TURBINE, NATURAL GAS-FIRED	9,160.0 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1,313.0 MM BTU/HR	119 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER INJECTION	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585.0 MMBTU/HR	0.033 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0010	PEDRICKTOWN COGENERATION LIMITED PARTNERSHIP	OLDMANS TOWNSHIP	2/23/90	4/30/93	TURBINE, NATURAL GAS FIRED	1,000.0 MMBTU/HR	0.044 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0011	LINDEN COGENERATION TECHNOLOGY	LINDEN	1/21/92	4/30/93	TURBINE, NATURAL GAS FIRED	50.0 X E12 BTU/YR	33.8 LB/HR	STEAM INJECTION AND SCR	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1,190.0 MMBTU/HR (EACH)	0.033 LB/MMBTU	SCR, DRY LOW NOX BURNER	BACT-OTHER
NJ-0017	NEWARK BAY COGENERATION PARTNERSHIP, L.P.	NEWARK	6/9/93	5/29/95	TURBINES, COMBUSTION, NATURAL GAS-FIRED (2)	617.0 MMBTU/HR (EACH)	8.3 PPMDV	SCR	BACT-PSD
NJ-0030	HOFFMAN-LA ROCHE, NUTLEY COGEN FACILITY	NUTLEY	5/8/96	2/2/99	TURBINE, GM LM500	86.6 MMBTU/H	0.34 LB/MMBTU		RACT
NJ-0031	UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NEWARK	6/26/97	2/17/99	COMBUSTION TURBINE COGENERATION UNITS, 3	56.0 MMBTU/H	0.167 LB/MMBTU NAT.GAS		RACT
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	TURBINE, GAS-FIRED	11,257.0 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DRY LOW NOX TECHNOLOGY	BACT-PSD
NM-0022	MARATHON OIL CO. - INDIAN BASIN N.G. PLAN	CARLSBAD	1/11/95	4/26/95	TURBINES, NATURAL GAS (2)	5,500.0 HP	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DRY/LOW NO	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900.0 MMCF/DAY	9 PPM @ 15% O2	DRY LOW NOX (GENERAL ELECTRI	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATION	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	15 PPM; SEE FAC. NOTES	DRY LOW NOX COMBUSTION	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHAM STA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100.0 MW	0 SEE FACILITY NOTES	DRY LOW NOX COMBUSTION	BACT-PSD
NM-0031	LORDSBURG L.P.	LORDSBURG	6/18/97	9/29/97	TURBINE, NATURAL GAS-FIRED, ELEC. GEN.	100.0 MW	74.4 LBS/HR	DRY LOW-NOX TECHNOLOGY WHICH ADOPTS STAGED OR	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375.0 MMBTU/H	15 PPM	WATER INJECTION FOLLOWED BY SELECTIVE CATALYTIC R	BACT-PSD
NV-0013	LAS VEGAS COGENERATION LTD. PARTNERSHIP	NORTH LAS VEGAS	10/18/90	3/24/95	TURBINE, COMBUSTION COGENERATION	397.0 MMBTU/H	10 PPM @ 15% O2	H2O INJECTION/SCR	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLANT	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600.0 MW (8 UNITS 75 EA	88.5999 TPY (EACH TURBINE)	LOW NOX COMBUSTOR	BACT-PSD
NV-0018	NEVADA COGENERATION ASSOCIATES #2	LAS VEGAS	1/17/91	3/24/95	COMBINED-CYCLE POWER GENERATION	85.0 MW POWER OUTPU	61.26 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NV-0020	NEVADA COGENERATION ASSOCIATES #1	LAS VEGAS	1/17/91	3/24/95	COMBINED-CYCLE POWER GENERATION	85.0 MW TOTAL OUTPU'	61.26 LBS/HR	SELECTIVE CATALYTIC SYSTEM ON ONE UNIT	BACT-PSD
NY-0036	ONEIDA COGENERATION FACILITY	ONEIDA	2/26/90	5/18/90	TURBINE, GE FRAME 6	417.0 MMBTU/H	32 PPM GAS	COMBUSTION CONTROL	OTHER
NY-0037	MEGAN-RACINE ASSOCIATES, INC.	CANTON	3/6/89	5/18/90	TURBINE, LM5000	430.0 MMBTU/H	42 PPM GAS	H2O INJECTION	BACT-PSD
NY-0038	EMPIRE ENERGY - NIAGARA COGENERATION CO.	LOCKPORT	5/2/89	5/18/90	TURBINE, GR FRAME 6, 3 EA	416.0 MMBTU/H	42 PPM GAS FIRING	STEAM INJECTION	BACT-PSD
NY-0039	FULTON COGENERATION ASSOCIATES	FULTON	1/29/90	5/18/90	TURBINE, GE LM5000, GAS FIRED	500.0 MMBTU/H	36 PPM GAS FIRING	H2O INJECTION	BACT-PSD
NY-0040	JMC SELKIRK, INC.	SELKIRK	11/21/89	5/18/90	TURBINE, GE FRAME 7, GAS FIRED	80.0 MW	25 PPM GAS FIRING	STEAM INJECTION	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	TURBINE, NATURAL GAS FIRED	240.0 MW	3.5 PPM @ 15% O2	SCR	LAER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINES (2) (252 MW)	1,173.0 MMBTU/HR (EACH)	9 PPM GAS	STEAM INJECTION AND SCR	BACT-OTHER
NY-0045	SELKIRK COGENERATION PARTNERS, L.P.	SELKIRK	6/18/92	9/13/94	COMBUSTION TURBINE (79 MW)	1,173.0 MMBTU/HR	25 PPM GAS	STEAM INJECTION	BACT-OTHER
NY-0046	SARANAC ENERGY COMPANY	PLATTSBURGH	7/31/92	9/13/94	TURBINES, COMBUSTION (2) (NATURAL GAS)	1,123.0 MMBTU/HR (EACH)	9 PPM	SCR	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653.0 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	11/24/92	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2,133.0 MMBTU/HR (EACH)	4.5 PPM	SCR AND DRY LOW NOX	BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550.0 MMBTU/HR	25 PPM, 47 LB/HR	STEAM INJECTION, FUEL SPEC; NATURAL GAS ONLY	BACT
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSE	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5,500.0 HP (EACH)	1.6 G/HP-HR*	LOW NOX COMBUSTION	BACT-OTHER
OR-0007	PACIFIC GAS TRANSMITION	MADRAS	11/3/89	7/20/94	TURBINE, NAT. GAS	14,600.0 HP	42 PPM @ 15% O2	LOW NOX BURNERS	BACT-PSD
OR-0009	PACIFIC GAS TRANSMISSION COMPANY	MADRAS	6/19/90	7/20/94	TURBINE GAS, COMPRESSOR STATION	110.0 MMBTU/HR	199 PPM @ 15% O2	LOW NOX BURNER DESIGN	NSPS
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1,720.0 MMBTU	4.5 PPM @ 15% O2	SCR	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	7/7/94	1/27/99	TURBINES, NATURAL GAS (2)	1,696.0 MMBTU/H	4.5 PPM @ 15% O2	SCR	BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	TURBINES, GAS, 2	34.6 KW EACH	25 PPM @ 15% O2	STEAM INJECTION/+SCR IN 1997	OTHER
PA-0099	FLEETWOOD COGENERATION ASSOCIATES	FLEETWOOD	4/22/94	11/22/94	NG TURBINE (GE LM6000) WITH WASTE HEAT BOILER	360.0 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS	BACT-OTHER
PA-0130	PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN)	MEHOOPANY	5/31/95	11/27/95	TURBINE, NATURAL GAS	580.0 MMBTU/HR	55 PPM @ 15% O2	STEAM INJECTION	RACT
PA-0148	BLUE MOUNTAIN POWER, LP	RICHLAND	7/31/96	1/12/99	COMBUSTION TURBINE WITH HEAT RECOVERY BOILER	153.0 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTIOI	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5.0 MW	25 PPMV@15%O2	SOLONOX BURNER: LOW NOX BURNER	BACT-OTHER
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0 MW	60 LB/HR	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC RE	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461.0 MW	73 LB/HR	STEAM/WATER INJECTION AND SELECTIVE CATALYTIC RE	BACT-PSD
RI-0008	PAWTUCKET POWER	PAWTUCKET	1/30/89	3/31/91	TURBINE/DUCT BURNER	533.0 MMBTU/H	9 PPM @ 15% O2, GAS	SCR	BACT-PSD

Table 5-22. RBLC NO_x Summary for Natural Gas Fired CTGs (Page 3 of 3)

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate		Emission Limit	Control System Description	Basis
RI-0010	NARRAGANSETT ELECTRIC/NEW ENGLAND POWER CO.	PROVIDENCE	4/13/92	5/31/92	TURBINE, GAS AND DUCT BURNER	1,360.0	MMBTU/H EACH	9 PPM @ 15% O2, GAS	SCR	BACT-PSD
RI-0012	ALGONQUIN GAS TRANSMISSION CO.	BURRILLVILLE	7/31/91	5/31/92	TURBINE, GAS, 2	49.0	MMBTU/H	100 PPM @ 15% O2	LOW NOX COMBUSTION	BACT-OTHER
RI-0018	TIVERTON POWER ASSOCIATES	TIVERTON	2/13/98	2/8/99	COMBUSTION TURBINE, NATURAL GAS	265.0	MW	3.5 PPM @ 15% O2	SCR	LAER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110.0	MEGAWATTS	308 LBS/HR	WATER INJECTION	BACT-PSD
TX-0231	WEST CAMPUS COGENERATION COMPANY	COLLEGE STATION	5/2/94	10/31/94	GAS TURBINES	75.3	MW (TOTAL POWEI	200 TPY	INTERNAL COMBUSTION CONTROLS	BACT-PSD
VA-0161	RICHMOND POWER ENTERPRISE PARTNERSHIP	RICHMOND	12/12/89	4/30/90	TURBINE, GAS FIRED, 2	1,163.5	MMBTU/H	8.2 PPM @ 15% O2 NAT GAS	SCR, STEAM INJECTION	LAER
VA-0163	VIRGINIA POWER		9/7/89	4/30/90	TURBINE, GAS	1,308.0	MMBTU/H	42 PPM @ 15% O2 NAT	H2O INJECTION, RECORD KEEPING OF FUEL N2 CONTENT	BACT-PSD
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0	MMBTU/H	9 PPM @ 15% O2	DRY COMBUSTOR TO 25 PPM SCR TO 9 PPM USING NAT GA!	OTHER
VA-0177	DOSWELL LIMITED PARTNERSHIP		5/4/90	3/24/95	TURBINE, COMBUSTION	1,261.0	MMBTU/H	65 PPM @ 15% O2	STEAM INJECTION & FUEL SPEC: USE OF #2 OIL	OTHER
VA-0179	COMMONWEALTH GAS PIPELINE CORPORATION	LOUISA STATION	8/17/90	3/24/95	SOLAR SATURN T-1300,3	14,460.0	CF/H	76 PPMVD		BACT-PSD
VA-0180	COMMONWEALTH GAS PIPELINE CORPORATION	GOOCHLAND	9/30/90	3/24/95	TURBINES, GAS FIRED, SINGLE CYCLE, 5	14.5	MMBTU/H EACH	0	EQUIPMENT DESIGN & OPERATION	BACT-PSD
VT-0005	ARROWHEAD COGENERATION CO.		12/20/89	2/28/90	TURBINE, COMBUSTION & BURNER, COGEN., 3	282.0	MMBTU/H, GAS	9 PPMVD AT ISO COND &	SCR, WATER INJECTION	OTHER
WA-0025	MARCH POINT COGENERATION CO		10/26/90	5/21/91	TURBINE, GAS-FIRED	80.0	MW	25 PPM @ 15% O2	MASSIVE STEAM INJECTION	BACT-PSD
WA-0026	SUMAS ENERGY INC	SUMAS	12/1/90	5/21/91	TURBINE, GAS-FIRED	67.0	MW	9 PPM @ 15% O2	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88.0	MW	6 PPM @ 15% O2	SCR	BACT-PSD
WA-0274	NORTHWEST PIPELINE COMPANY	SUMAS	8/13/92	4/5/95	TURBINE, GAS-FIRED	12,100.0	HP	196 PPM @ 15% O2	ADVANCED DRY LOW NOX COMBUSTOR (BY 07/01/95)	BACT-PSD
WY-0032	QUESTAR PIPELINE CORP. - RK SPRINGS COMPRESSOR COM	ROCK SPRINGS	9/25/97	2/1/99	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 2EA	1,001.0	HP	2.8 G/B-HP-H		BACT-PSD
WY-0039	TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHIP	15 MILES SE OF WRIGHT	2/27/98	3/31/99	TURBINE, STATIONARY	33.3	MW	25 PPM @ 15% O2	DRY LOW NOX BURNERS	BACT-PSD

Source: RBLC 2000.

MAXIMUM	225.0	PPM @ 15% O2
MINIMUM	2.0	PPM @ 15% O2
MEDIAN	10.5	PPM @ 15% O2

Table 5-23. Florida BACT NO_x Summary—Natural Gas-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_x Emission Limit (ppmvd)	Control Technology
3/7/95	Orange Cogeneration, L.P.	39	25	Good combustion
7/10/98	City of Lakeland McIntosh Unit 5	250	25	Good ombustion
9/29/98	Florida Power Corporation Hines Energy Complex	165	12	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	9	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/04/98	Santa Rosa Energy, LLC (DB On)	167	9.8	Good combustion
7/23/99	Seminole Electric Cooperative, Inc., Payne Creek	158	9	Good combustion
10/8/99	Tampa Electric Company—Polk Power Station	165	10.5	Good combustion
10/8/99	TECO Power Services—Hardee Power Station	75	9.0	Good combustion
10/18/99	Vandolah Power Project	170	9	Good combustion
12/28/99	Reliant Energy Osceola	170	10.5	Good combustion
1/13/00	Shady Hills Generating Station	170	9	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB Off)	167	3.5	Good combustion
2/00	Kissimmee Utility—Cane Island Unit 3 (DB On)	167	3.5	Good combustion
2/24/00	Gainesville Regional Utilities	83	9	Good combustion
5/11/00	Calpine Osprey (Draft—DB Off)	170	3.5	Good combustion
5/11/00	Calpine Osprey (Draft—DB On)	170	3.5	Good combustion

Source: FDEP, 2000.

Table 5-24. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits*	
	lb/hr	ppmvd†
CTG/HRSG Units (per unit)	31.9	3.5

*24-hour block average.
†Corrected to 15-percent O_2.

Sources: Calpine, 2000.
ECT, 2000.

The liquid sulfite/sulfate salts that form from the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream and subsequently removed by downstream PM control equipment.

Technical Feasibility

Treatment of natural gas and fuel oils to remove sulfur compounds is conducted by the fuel supplier, when necessary, prior to distribution. Accordingly, additional fuel treatment by end users is considered technically infeasible because the natural gas and distillate fuel oil sulfur contents have already been reduced to very low levels.

There have been no applications of FGD technology to CTGs because low-sulfur fuels are typically used. The BHEC CTGs and HRSG DBs will be fired exclusively with natural gas. The sulfur content of natural gas is more than 100 times 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.

5.6.2 PROPOSED BACT EMISSION LIMITATIONS

Because postcombustion SO_2 and H_2SO_4 mist controls are not applicable, use of low-sulfur fuel is considered to represent BACT for the BHEC CTG/HRSGs. Pipeline quality natural gas used at the BHEC will contain no more than 1.5 gr S/100 dscf. The proposed BACT limits are based on the use of natural gas containing no more than 1.5 gr S/100 dscf. Table 5-25 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the BHEC.

Table 5-25. Proposed SO_2 and H_2SO_4 Mist BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits Fuel Sulfur Content (gr S/100 dscf)
CTG/HRSG Units		
	SO_2	Pipeline Quality Natural Gas (1.5 gr S/100 dscf)
	H_2SO_4 mist	Pipeline Quality Natural Gas (1.5 gr S/100 dscf)

Sources: Calpine, 2000.
ECT, 2000.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-26 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-27 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-26. Summary of BACT Control Technologies

Pollutant	Means of Control
CTGs and HRSG DBs	
PM/PM_{10}	• Exclusive use of low-sulfur and low-ash natural gas. • Efficient combustion.
CO and VOC	• Efficient combustion.
NO_x	• Use of advanced dry low-NO_x combustor and low-NO_x burner technologies and selective catalytic reduction (SCR).
SO_2/H_2SO_4 mist	• Exclusive use of low-sulfur natural gas.
Cooling Tower	
PM/PM_{10}	• Efficient drift elimination.

Source: ECT, 2000.

Table 5-27. Summary of Proposed BACT Emission Limitations

Pollutant	Proposed BACT Emission Limits (ppmvd @ 15% O_2)	(lb/hr)
Siemens Westinghouse 501F CTG/HRSG (per CTG/HRSG Unit)		
A. All Operating Scenarios		
NO_X	3.5	31.9
PM/PM_{10}	≤10% opacity	
SO_2	Fuel ≤1.5 gr S/100 dscf	
H_2SO_4	Fuel ≤1.5 gr S/100 dscf	
B. 100-Percent Load Without Steam Power Augmentation, Without DB Firing		
CO	10.0	46.0
VOC	1.2	3.2
C. 100-Percent Load Without Steam Power Augmentation, With DB Firing		
CO	15.6	74.9
VOC	3.4	9.0
D. 100-Percent Load With Steam Power Augmentation, Without DB Firing		
CO	25.0	121.0
VOC	1.2	3.3
E. 100-Percent Load With Steam Power Augmentation, With DB Firing		
CO	38.5	193.2
VOC	6.6	17.7
F. 60- to 70-Percent Load Without Steam Power Augmentation, Without DB Firing		
CO	50.0	155.0
VOC	3.0	5.3
Main Cooling Towers		
PM/PM_{10}	0.002 percent drift loss rate	
Wastewater Cooling Tower		
PM/PM_{10}	0.0005 percent drift loss rate	

Sources: Calpine, 2000.
ECT, 2000.
Siemens Westinghouse, 2000.

6.0 AMBIENT IMPACT ANALYSIS METHODOLOGY

6.1 GENERAL APPROACH

The approach used to analyze the potential impacts of the proposed facility, as described in detail in the following sections, was developed in accordance with accepted dispersion modeling practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the BHEC Project will have potential emissions of 453.2 tpy NO_x, 1,839.8 tpy of CO, 452.8 tpy of PM, 408.5 tpy of PM_{10}, 145.1 tpy of SO_2, 140.6 tpy of VOCs, 0.5 tpy of lead, 26.6 tpy of H_2SO_4 mist, and 0.0013 tpy of mercury. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the BHEC Project and the PSD significant emission rate thresholds. As shown in that table, potential emissions of NO_x, CO, PM/PM_{10}, SO_2, VOCs, and H_2SO_4 mist are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR air quality impact analysis requirements of Rule 62-212.400(5)(d), F.A.C.

The ambient impact analysis addresses NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist. Because VOCs contribute to the formation of ground-level ozone and because ozone modeling is conducted on a regional scale, modeling of ozone impacts due to BHEC VOC emissions was not conducted.

6.3 MODEL SELECTION AND USE

For this study, air quality models were applied at two levels. The first, or screening, level provided conservative estimates of impacts from the BHEC Project emission sources. The purposes of the screening modeling were to:

- Eliminate the need for more sophisticated analysis in situations with low predicted impacts and no threat to any standard.

- Provide information to guide the more rigorous refined analysis, including the operating mode (load, fuel type, and ambient temperature), which caused the highest ambient impact for each criteria pollutant.

The second, or refined, level encompassed a more detailed treatment of atmospheric processes. Refined modeling required more detailed and precise input data, but is presumed to have provided more accurate estimates of source impacts.

6.3.1 SCREENING MODELS

For screening purposes, the Industrial Source Complex Short-Term (ISCST3) model, Version 00101, was used with a range of predefined, worst-case meteorological conditions. The worst-case meteorological conditions (54 combinations of windspeed and stability class) were taken from the SCREEN3 model (Version 96043) and represent a conservative, full range of potential weather conditions. For stability classes A through D (unstable through neutral conditions), mixing heights were set equal to 320 times the 10-meter windspeed in accordance with the SCREEN3 model procedure. For stability classes E and F (stable conditions), mixing heights were set equal to 5,000 meters to represent unlimited mixing. Ambient temperatures used in the screening meteorology corresponded to the particular CTG/HRSG scenario evaluated. Thirty-six wind directions were assigned at 10-degree (°) intervals beginning at 10° and ending at 360°. The screening meteorological dataset, therefore, consisted of 81 days of hourly data (i.e., 54 windspeed/stability class combinations times 36 wind directions).

Use of the ISCST3 model with the screening meteorology described above is considered to provide a better analysis of worst-case CTG/HRSG operating scenarios (i.e., to determine which CTG/HRSG operating scenario will cause the highest air quality impacts) than the SCREEN3 model because the same comprehensive receptor grids and direction-specific structure downwash procedures used in the refined dispersion modeling are employed.

The BHEC Project CTG/HRSG units will operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and alternative modes of operation (i.e., use of CTG inlet air evaporative coolers, CTG steam power augmentation, and HRSG duct burner firing). 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. Each of the operating scenarios was evaluated for each pollutant of concern to identify the scenario that caused the highest impact. These worst-case operating scenarios were then subsequently evaluated using the ISCST3 dispersion model and 5 years of actual, historical meteorological data (i.e., refined mode ISCST3 modeling). A nominal emission rate of 1.0 gram per second (g/s) was used for all ISCST3 screening mode model runs. The ISCST3 model results were then adjusted to reflect maximum emission rates for each operating case (i.e., model results were multiplied by the ratio of maximum emission rates [in g/s] to 1.0 g/s). ISCST3 screening modeling results are summarized in Section 7.0, Tables 7-1 through 7-5. These tables show, for each operating scenario and pollutant evaluated, the ISCST3 screening mode unadjusted 1-hour average maximum impact, emission rate adjustment ratio, and the adjusted ISCST3 screening mode 1-hour average maximum impact.

6.3.2 REFINED MODELS

The most recent regulatory versions of the ISC3 models (EPA, 2000) are recommended by FDEP and were used in this analysis for refined modeling. The ISC3 models are steady-state Gaussian plume models that can be used to assess air quality impacts over simple terrain from a wide variety of sources. The ISC3 models are capable of calculating concentrations for averaging times ranging from 1 hour to annual. For this study, the ISCST3 (Version 00101) model was used to calculate short-term ambient impacts with averaging times between 1 and 24 hours as well as long-term annual averages.

Procedures applicable to the ISCST3 dispersion model specified in EPA's *Guideline for Air Quality Models* (GAQM) were followed in conducting the refined dispersion modeling. The GAQM is codified in Appendix W of 40 CFR 51. In particular, the ISCST3 model control pathway MODELOPT keyword parameters DFAULT, CONC, RURAL, and NOCMPL were selected. Selection of the parameter DFAULT, which specifies use of the regulatory default options, is recommended by the GAQM. The CONC, RURAL, and NOCMPL parameters specify calculation of concentrations, use of rural dispersion, and suppression of complex terrain calculations, respectively. As previously mentioned, the ISCST3 model was also used to determine annual average impact predictions, in addition to short-term averages, by using the PERIOD parameter for the AVERTIME keyword. Conservatively, no consideration was given to pollutant exponential decay.

6.3.3 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.

6.4 DISPERSION OPTION SELECTION

Area characteristics in the vicinity of proposed emission sources are important in determining model selection and use. One important consideration is whether the area is rural or urban since dispersion rates differ between these two classifications. EPA guidance provides two procedures to determine whether the character of an area is predominantly urban or rural. One procedure is based on land use typing, and the other is based on population density. The land use typing method uses the work of Auer (Auer, 1978) and is preferred by EPA and FDEP because it is meteorologically oriented. In other words, the land use factors employed in making a rural/urban designation are also factors that have a direct effect on atmospheric dispersion. These factors include building types, extent of vegetated surface area and water surface area, types of industry and commerce, etc. Auer recommends these land use factors be considered within 3 km of the source to be modeled to determine urban or rural classifications. The Auer land use typing method was used for the ambient impact analysis.

The Auer technique recognizes four primary land use types: industrial (I), commercial (C), residential (R), and agricultural (A). Practically all industrial and commercial areas come under the heading of urban, while the agricultural areas are considered rural. However, those portions of generally industrial and commercial areas that are heavily vegetated can be considered rural in character. In the case of residential areas, the delineation between urban and rural is not as clear. For residential areas, Auer subdivides this land use type into four groupings based on building structures and associated vegetation. Accurate classification of the residential areas into proper groupings is important to determine the most appropriate land use classification for the study area.

U.S. Geological Survey (USGS) 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. Land use within a 3-km radius of the BHEC is predominantly agricultural (i.e., tree crops and pastureland) with a residential development situated to the southeast of the site. Based on this land use, the area within a 3-km radius would be characterized as rural using the Auer classification method. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

6.5 TERRAIN CONSIDERATION

The GAQM defines *flat terrain* as terrain equal to the elevation of the stack base, *simple terrain* as terrain lower than the height of the stack top, and *complex terrain* as terrain above the height of the plume center line (for screening modeling, complex terrain is terrain above the height of the stack top). Terrain above the height of the stack top but below the height of the plume center line is defined as *intermediate terrain*.

USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the BHEC Project (i.e., within an approximate 10-km radius). Review of the USGS topographic maps indicates nearby terrain would be classified as ranging from flat to simple terrain. Due to the minimal amount of terrain elevation differences in the vicinity, assignment of receptor terrain elevations was not conducted (i.e., all receptors were assumed to be at the same elevation as the CTG/HRSG stack base for modeling purposes).

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

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

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

where: Hg = GEP stack height.

H = height of the structure or nearby structure.

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

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

The stack heights proposed for the BHEC CTG/HRSGs, main cooling towers, and wastewater cooling tower (135, 62, and 21 feet [ft], respectively) are each less than the *de minimis* GEP height of 65 meters (213 ft), and, therefore, comply with the EPA promulgated final stack height regulations (40 CFR 51).

While the GEP stack height rules address the maximum stack height that can be employed in a dispersion model analysis, stacks having heights lower than GEP stack height can potentially result in higher downwind concentrations due to building downwash effects. The ISC3 dispersion models contain two algorithms that assess the effect of building downwash; these algorithms are referred to as the Huber-Snyder and Schulman-Scire methods. The following steps are employed in determining the effects of building downwash:

- A determination is made as to whether a particular stack is located in the area of influence of a building (i.e., within five times the lesser of the building's height or projected width). If the stack is not within this area, it will not be subject to downwash from that building.

- If a stack is within a building's area of influence, a determination is made as to whether it will be subject to downwash based on the heights of the stack and building. If the stack height to building height ratio is equal to or greater than 2.5, the stack will not be subject to downwash from that building.
- If both conditions in the previous two items are satisfied (i.e., a stack is within the area of influence of a building and has a stack height to building height ratio of less than 2.5), the stack will be subject to building downwash. The determination is then made as to whether the Huber-Snyder or Schulman-Scire downwash method applies. If the stack height is less than or equal to the building height plus one-half the lesser of the building height or width, the Schulman-Scire method is used. Conversely, if the stack height is greater than this criterion, the Huber-Snyder method is employed.
- The ISCST3 downwash input data consists of an array of 36 wind direction-specific building heights and projected widths for each stack. LB is defined as the lesser of the height and projected width of the building. For directionally dependent building downwash, wake effects are assumed to occur if a stack is situated within a rectangle composed of two lines perpendicular to the wind direction, one line at 5 LB downwind of the building and the other at 2 LB upwind of the building, and by two lines parallel to the wind, each at 0.5 LB away from the side of the building.

For the ambient impact analysis, the complex downwash analysis described previously was performed using the current version of EPA's Building Profile Input Program (BPIP) (Version 95086). 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. Table 6-1 provides dimensions of the building/structures evaluated for wake effects; the locations of these buildings/structures were previously provided on Figure 2-2. A three-dimensional representation of the BHEC downwash structures is shown on Figure 6-1. BPIP output consists of

Table 6-1. Building/Structure Dimensions

Facility	Elevation* (ft)	Length (ft)	Width (ft)
Inlet air filters	44	50	50
HRSG stacks	135	19†	N/A
HRSG	83	100	38
Service/fire water tank	42	58†	N/A
Demineralizer tanks (2)	37	35†	N/A
Control building	55	96	117
Warehouse	27	96	71
Water treatment building	27	96	67
Raw water tank	65	92†	N/A
Fire pump house	18	63	30
CT electrical room	18	75	54
Cooling towers	52	432	50
Cooling tower stacks	62	28†	N/A
Wastewater cooling tower	16	57	20
Wastewater cooling tower stacks	21	10.5†	N/A

*Above ground surface.
†Diameter.

Source: Calpine, 2000.

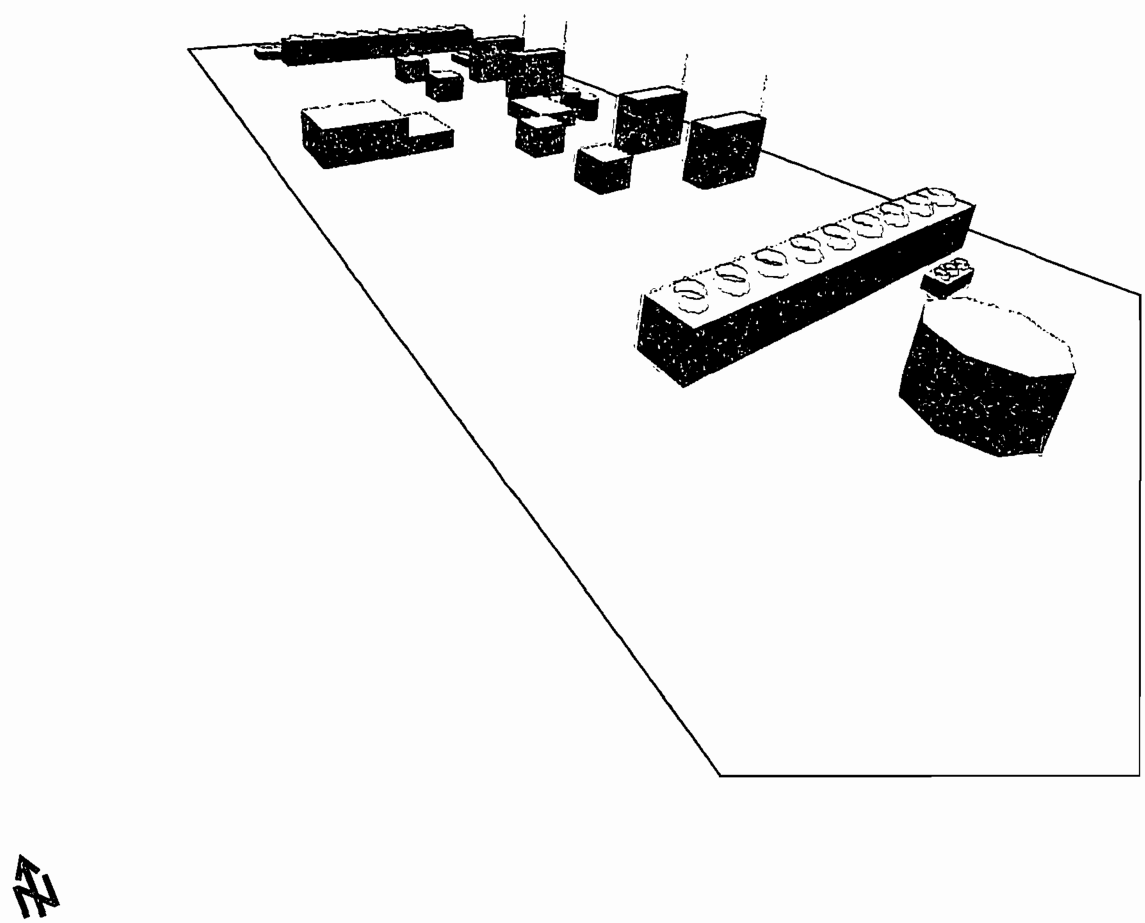

FIGURE 6-1.
DOWNWASH SCHEMATIC

Source: ECT, 2000.

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an array of 36 direction-specific (10° to 360°) building heights and projected building widths for each stack suitable for use as input to the ISCST3 model.

6.7 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." Section 2.0 provided a plot plan showing the site fence lines (see Figure 2-2). As shown in Figure 2-2, the entire perimeter of the plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

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

- Fence line Cartesian receptors—Discrete receptors placed on the site fence line at approximately 50-meter intervals.
- Near-field Cartesian receptors—Discrete receptors placed at 50-meter intervals from the site fence line to the first polar receptor ring.
- Near-field polar receptors—Polar receptors consisting of 15 rings of 36 receptors each (36 radials at 10° radial spacings) at 50-meter intervals beginning 250 meters from the receptor grid origin (Units 7 and 8 common stack) to a distance of 950 meters.
- Mid-field polar receptors—Polar receptors consisting of 10 rings of 36 receptors each (36 radials at 10° radial spacings) at 100-meter intervals beginning 1,000 meters from the receptor grid origin to a distance of 1,900 meters.
- Far-field Polar receptors—Polar receptors consisting of 10 rings of 36 receptors each (36 radials at 10° radial spacings) at 1,000-meter intervals beginning 2,000 meters from the receptor grid origin to a distance of 10,000 meters.
- Far-field Polar receptors—Polar receptors consisting of 10 rings of 36 receptors each (36 radials at 10° radial spacings) at 1,000-meter intervals beginning 2,000 meters from the receptor grid origin to a distance of 10,000 meters.

- To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. Figure 6-2 illustrates a graphical representation of the receptor grids (out to a distance of 1 km). A depiction of the receptor grids (from 1 to 10 km) is shown in Figure 6-3.

6.8 METEOROLOGICAL DATA

Detailed meteorological data are needed for modeling with the ISC3 dispersion models. The ISCST3 model requires a preprocessed data file compiled from hourly surface observations and concurrent twice-daily rawinsonde soundings (i.e., mixing height data).

Consistent with the GAQM and FDEP guidance, 5 consecutive years of the most recent, readily available, representative meteorological data were processed for the ambient impact analysis. For Indian River County, FDEP recommends use of West Palm Beach surface and upper air meteorological data in conducting the air quality analyses. The most recent 5 years of West Palm Beach station (West Palm Beach International Airport—Station No. 12844) surface and upper air meteorological data available from EPA's Support Center for Regulatory Air Models (SCRAM) website are calendar years 1987 through 1991. Vero Beach surface data was not recommended by the FDEP because 5 consecutive years are not available.

The surface and mixing height data for each of the 5 years were processed using the current version of EPA's PCRAMMET (Version 95300) meteorological preprocessing program to generate the meteorological data files in the format required by the ISCST3 dispersion model. PCRAMMET input files consist of the surface and mixing height files as obtained from the EPA SCRAM website. The mixing height file for each year must include mixing height records for December 31 of the year preceding the year of record and for January 1 of the year following the year of record. If records for these 2 days are unavailable, duplicate mixing height records are used with the year, month, and day changed appropriately.

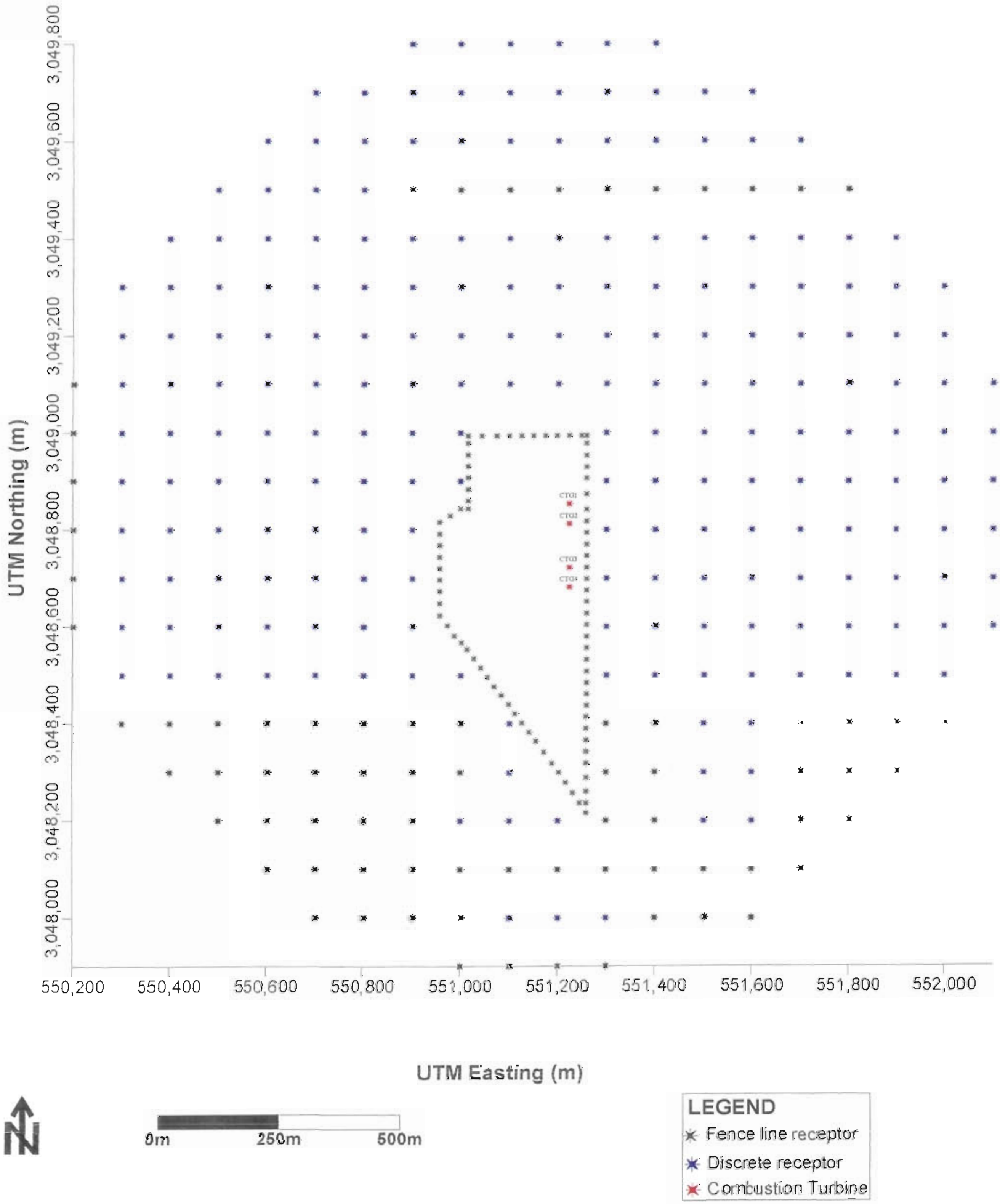

FIGURE 6-2.

RECEPTOR LOCATIONS (WITHIN 1 km)

Source: ECT, 2000.

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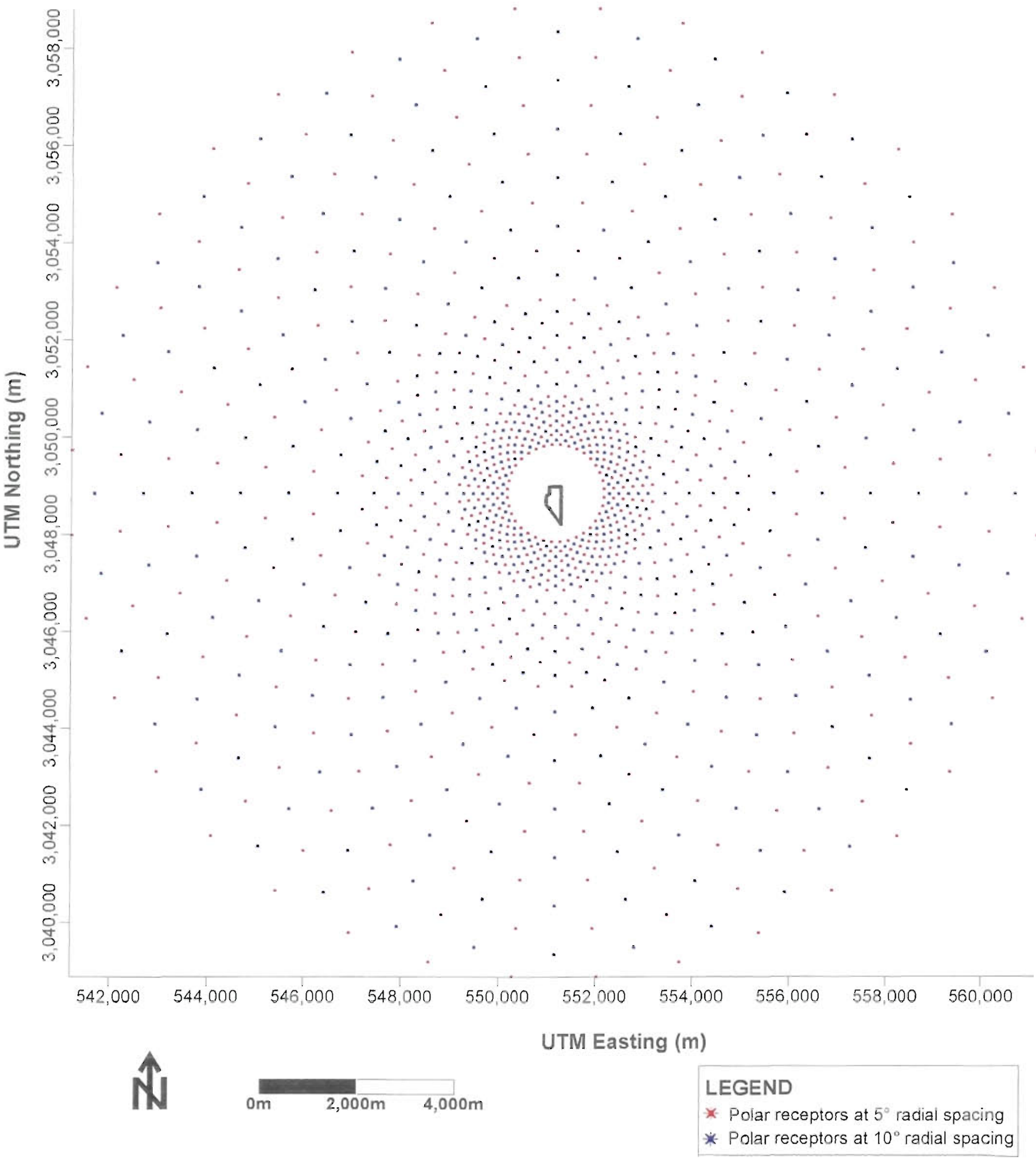

FIGURE 6-3.

RECEPTOR LOCATIONS (From 1 km to 10 km)

Source: ECT, 2000.

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In addition to the surface and mixing height meteorological data files, PCRAMMET requires input with respect to: (a) the use of dry or wet deposition calculations; (b) output filename; (c) output file type (UNFORM or ASCII); (d) surface data format (CD144, SAMSON, or SCRAM); and (e) latitude, longitude, and time zone of the surface meteorological station. In processing the West Palm Beach meteorological data, the NONE deposition option was selected, ASCII output file chosen, and the SCRAM surface data format utilized. As obtained from the EPA SCRAM web site, West Palm Beach station latitude and longitude coordinates (in decimal degrees) are 26.683 and 80.117, respectively. The West Palm Beach surface station is located in time zone 5.

Actual anemometer height for the West Palm Beach surface station, obtained from he National Climatic Data Center (NCDC), is 33 ft (10.1 meters) for the time period of interest (i.e., 1987 through 1991).

Processing of the West Palm Beach station meteorological data did not require any data replacement or substitution.

6.9 MODELED EMISSION INVENTORY

6.9.1 ON-PROPERTY SOURCES

The modeled BHEC emission sources included the four CTG/HRSG units, north and south main cooling towers, and one wastewater cooling tower. In addition to these emission sources, the BHEC will include one diesel fuel-fired emergency electrical generator engine and one diesel fuel-fired emergency firewater pump engine. Because of the negligible emissions associated with the infrequently operated emergency diesel internal combustion engines, these emission sources were not addressed in the ambient impact analysis. Emission rates and stack parameters for the BHEC emission sources were previously presented in Tables 2-1 through 2-11.

As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the BHEC emission sources resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods, with the exception of PM_{10}. Accordingly, additional, multi-source interactive dispersion modeling was required for PM_{10} only.

6.9.2 OFF-PROPERTY SOURCES

An inventory of PM/PM_{10} emission sources within approximately 60 km of the BHEC was obtained from FDEP. A summary of the FDEP off-property PM_{10} emission sources is provided on Table 6-2.

Off-property PM/PM_{10} emission sources included in the BHEC dispersion modeling analysis consisted of all emission sources listed on Table 6-2 located within 53 km of the project site; i.e., within the 3-km significant impact area (SIA) distance plus 50 km, having data available for modeling purposes. A summary of the modeled off-property PM/PM_{10} emission sources is provided on Table 6-3.

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	(g/s)	(tpy)	Stack Parameters Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
INDIAN RIVER COUNTY UTILITIES	9	0610015	2	550.5	3,050.6	1.9	40.000	5.040	41.60		1,366.5		
AMERICAN POWER TECH	7	0610080	1	550.7	3,051.1	2.4	0.796	0.100	3.48	17.4	394.3	16.18	0.91
AMERICAN POWER TECH	8	0610080	2	550.7	3,051.1	2.4	0.796	0.100	3.48	17.4	394.3	16.18	0.91
OCEAN SPRAY CRANBERRIES	1	0610021	1	550.6	3,051.3	2.6	0.110	0.014	0.48	9.1	491.5	7.62	0.64
OCEAN SPRAY CRANBERRIES	2	0610021	2	550.6	3,051.3	2.6	0.110	0.014	0.48	9.1	491.5	3.96	0.76
OCEAN SPRAY CRANBERRIES	3	0610021	3	550.6	3,051.3	2.6	0.110	0.014	0.48	9.1	491.5	17.07	0.46
OCEAN SPRAY CRANBERRIES	4	0610021	4	550.6	3,051.3	2.6	17.300	2.180	30.52	18.3	341.5	16.89	0.85
OCEAN SPRAY CRANBERRIES	5	0610021	5	550.6	3,051.3	2.6	8.560	1.079	26.46	11.0	310.9	9.36	0.91
OCEAN SPRAY CRANBERRIES	6	0610021	6	550.6	3,051.3	2.6	17.300	2.180	30.52	18.3		22.49	0.85
SHADY OAK PET CREMATORY	10	0610042	1	560.2	3,052.9	9.9	0.020	0.003	0.10	3.7	788.7	9.75	0.30
FLORIDA MINING & MATERIALS CORPORATION	16	0610035	1	560.8	3,052.7	10.3	0.023	0.003	0.10	9.1	299.8		0.46
FLORIDA MINING & MATERIALS CORPORATION	17	0610035	2	560.8	3,052.7	10.3	0.023	0.003	0.10	9.1	299.8		0.46
VERO BEACH CITRUS PACKERS	20	0610016	1	560.6	3,054.2	10.8	0.400	0.050	0.30	5.8	472.0	1.52	0.61
LOWTHER, THOMAS	11	0610077	1	558.6	3,057.0	11.0	0.430	0.054	1.90	5.5	922.0	4.94	0.52
RINKER/VERO BEACH	14	0610003	1	559.9	3,055.7	11.1	1.340	0.169	5.69	19.8	302.6	6.40	3.02
RINKER/VERO BEACH	15	0610003	2	559.9	3,055.7	11.1	0.320	0.040	0.08	9.1	299.8	19.20	0.15
SOUTHEASTERN RACK COMPANY	13	0610037	2	559.4	3,056.4	11.2				12.2	377.6	5.49	0.24
RUSSELL CONCRETE	21	0610026	3	559.9	3,056.0	11.3	0.078	0.010	0.04	13.4	297.0	7.92	0.18
THE PACKERS OF INDIAN RIVER, INC.	22	0610032	1	559.4	3,057.5	11.9	2.600	0.328	1.84	7.6	477.6	48.46	0.61
THE NEW PIPER AIRCRAFT, INC	18	0610023	9	557.6	3,058.9	11.9				5.8	338.7	15.54	0.55
THE NEW PIPER AIRCRAFT, INC	19	0610023	13	557.6	3,058.9	11.9				12.5	433.2	7.47	0.38
WOOD WASTE RECYCLERS	12	0610074	1	554.5	3,060.5	12.1	5.708	0.719	25.00				
CITY OF VERO BEACH	23	0610029	1	561.4	3,056.5	12.8	14.000	1.764	76.70	61.0	415.9	32.15	1.07
CITY OF VERO BEACH	24	0610029	2	561.4	3,056.5	12.8	72.900	9.185	133.00	61.0	448.2	41.82	1.07
CITY OF VERO BEACH	25	0610029	3	561.4	3,056.5	12.8	41.000	5.166	224.50	61.0	445.4	20.91	1.83
CITY OF VERO BEACH	26	0610029	3	561.4	3,056.5	12.8	123.000	15.498	224.50	61.0	445.4	20.91	1.83
CITY OF VERO BEACH	27	0610029	4	561.4	3,056.5	12.8	68.500	8.631	300.00	61.0	412.6	23.68	2.13
CITY OF VERO BEACH	28	0610029	5	561.4	3,056.5	12.8	11.400	1.436	23.70	38.1	416.5	19.38	3.35
CITY OF VERO BEACH	29	0610029	5	561.4	3,056.5	12.8	2.500	0.315	23.70	38.1	416.5	19.38	3.35
CITY OF VERO BEACH	30	0610029	7	561.4	3,056.5	12.8							
INDIAN RIVER MEMORIAL HOSPITAL	31	0610017	3	559.8	3,059.4	13.6	0.050	0.006	0.22	2.1	477.6	7.01	0.40
INDIAN RIVER MEMORIAL HOSPITAL	32	0610017	5	559.8	3,059.4	13.6	0.900	0.113	3.90	7.6	477.6	7.01	0.40
ST LUCIE COUNTY INTL AIRPORT	42	1110042	1	561.9	3,040.0	13.8	0.228	0.029	0.50	8.5	1,255.4	4.57	0.30
RIVERFRONT GROVES	33	0610025	1	558.2	3,061.0	14.0	0.530	0.067	1.00	4.9	422.0	1.52	0.61
FLORIDA GAS TRANSMISSION	44	1110060	1	557.2	3,035.8	14.4	0.110	0.014	0.48	8.5	588.7	21.94	0.49
FLORIDA GAS TRANSMISSION	45	1110060	2	557.2	3,035.8	14.4	0.110	0.014	0.48	8.5	588.7	21.94	0.49
FLORIDA GAS TRANSMISSION	46	1110060	3	557.2	3,035.8	14.4	0.150	0.019	0.64	8.5	588.7	29.26	0.49
FLORIDA GAS TRANSMISSION	47	1110060	4	557.2	3,035.8	14.4	0.090	0.011	0.40	19.8	641.5	76.50	0.34
FLORIDA GAS TRANSMISSION	48	1110060	5	557.2	3,035.8	14.4	0.160	0.020	0.68	6.7	873.2	78.63	0.15
INDIAN RIVER PACKING CO	34	0610018	1	558.2	3,061.6	14.6	0.180	0.023	1.00	5.5	422.0	2.13	0.52
LEROY E SMITHS SONS	35	0610019	1	558.3	3,061.6	14.6	0.080	0.010	0.27	6.1	466.5	3.96	0.61
FELIX ASPHALT OF FLORIDA	36	0610001	1	557.0	3,062.5	14.9	9.340	1.177	19.89	9.1	299.8	2.53	1.19
TARMAC AMERICA INC	37	0610038	1	557.0	3,062.5	14.9	0.080	0.010	0.09	9.1	299.8	8.84	0.15
US DEPARTMENT OF AGRICULTURE	49	1110092	0	557.7	3,033.9	16.3					699.8		
ATLANTIC COAST RECYCLING, INC.	51	1110046	1	562.7	3,036.5	16.8				9.8	1,005.4	8.84	0.46
ATLANTIC COAST RECYCLING, INC.	52	1110046	2	562.7	3,036.5	16.8				9.8			0.76
AIRLITE PROCESSING CORP OF FLORIDA	40	0610002	2	557.0	3,065.2	17.4	3.590	0.452	15.72	3.7	469.3	21.33	0.46

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory (Page 2 of 4)

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	(g/s)	(tpy)	Stack Parameters Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
GREENE RIVER PACKING	38	0610068	1	556.6	3,065.4	17.4	0.271	0.034		5.5	533.2	1.34	0.67
GREENE RIVER PACKING	39	0610068	2	556.6	3,065.4	17.4	0.060	0.008	0.24	5.5	477.6	10.55	0.30
NOVARTIS CROP PROTECTION, INC.	41	0610033	1	553.7	3,066.8	18.1	0.530	0.067	0.78	9.4	1,144.3	7.62	0.55
MARCONA OCEAN INDUSTRIES	53	1110029	1	566.1	3,037.7	18.6	20.000	2.520	43.80	6.1	560.9	20.12	0.61
FLORIDA SUN CEMENT COMPANY, INC.	54	1110005	1	565.9	3,037.3	18.7				57.0		15.24	0.76
RUSSELL CONCRETE	43	0610081	1	555.9	3,067.0	18.8							
HAISLEY-HOBBS FUNERAL HOME	55	1110050	1	563.7	3,034.4	19.1	0.190	0.024	0.00	6.1	755.4	3.57	0.51
FT PIERCE UTILITIES AUTHORITY	56	1110003	1	566.1	3,036.4	19.4	10.420	1.313	45.66	7.0	783.2	11.89	0.91
FT PIERCE UTILITIES AUTHORITY	57	1110003	2	566.1	3,036.4	19.4	10.420	1.313	45.66	7.0	783.2	11.89	0.91
FT PIERCE UTILITIES AUTHORITY	58	1110003	3	566.1	3,036.4	19.4	25.330	3.192	110.66	20.7	492.0	18.23	3.41
FT PIERCE UTILITIES AUTHORITY	59	1110003	4	566.1	3,036.4	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	60	1110003	4	566.1	3,036.4	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	61	1110003	4	566.1	3,036.4	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	62	1110003	7	566.1	3,036.4	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	63	1110003	7	566.1	3,036.4	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	64	1110003	7	566.1	3,036.4	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	65	1110003	8	566.1	3,036.4	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
FT PIERCE UTILITIES AUTHORITY	66	1110003	8	566.1	3,036.4	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
FT PIERCE UTILITIES AUTHORITY	67	1110003	8	566.1	3,036.4	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
FT PIERCE UTILITIES AUTHORITY	68	1110003	9	566.1	3,036.4	19.4							
FT PIERCE UTILITIES AUTHORITY	69	1110003	10	566.1	3,036.4	19.4							
RINKER MATERIALS CORP	70	1110007	3	566.1	3,035.5	19.9							
YATES FUNERAL HOME	71	1110059	1	565.9	3,034.6	20.4	0.600	0.076	0.90	7.0	669.3	8.23	0.52
GRAVES BROTHERS CO	50	0610006	2	555.2	3,069.7	21.3	0.066	0.008	0.22	6.7	477.6	5.49	0.46
RANGER CONSTRUCTION INDUSTRIES INC	73	1110040	2	561.7	3,030.2	21.4	50.000	6.300	52.00	7.0	435.9	51.51	0.76
CONTINENTAL CONCRETE INC	72	1110061	1	562.3	3,030.5	21.4	0.200	0.025	0.30	15.8	298.2		0.21
PRESTIGE GUNITE OF FT. PIERCE INC.	74	1110084	1	562.0	3,030.3	21.4				18.3	298.2	258.70	0.15
CONTINENTAL CONCRETE INC.	75	1110001	1	561.4	3,030.0	21.4	1.270	0.160	4.38	17.7	298.2	7.62	0.15
TRS CONCRETE RECYCLING	82	7775058	1	557.6	3,028.3	21.5							
TRS CONCRETE RECYCLING	83	7775058	2	557.6	3,028.3	21.5				4.6			0.09
SUN PURE LTD	76	1110018	1	562.4	3,030.5	21.5				6.4	464.8		9.75
SUN PURE LTD	77	1110018	7	562.4	3,030.5	21.5	30.570	3.852	61.14	29.0	333.2	10.06	1.46
SUN PURE LTD	78	1110018	9	562.4	3,030.5	21.5				7.3	469.3	18.59	0.67
SUN PURE LTD	79	1110018	10	562.4	3,030.5	21.5							
SUN PURE LTD	80	1110018	11	562.4	3,030.5	21.5	21.540	2.714	43.08	6.1	310.9	31.33	0.52
DICKERSON FLORIDA, INC	81	1110010	3	562.2	3,030.4	21.5	12.550	1.581	21.34	7.9	400.9	24.90	1.25
LYKES AGRI SALES, INC.	84	1110065	1	562.8	3,030.5	21.7	0.170	0.021	0.32	1.8	352.6	51.75	0.08
TARMAC FLORIDA	85	1110002	1	561.6	3,029.7	21.7				13.7	298.2	181.04	0.06
TROPICANA PRODUCTS, INC	87	1110004	1	559.6	3,028.3	22.1	19.240	2.424	84.27	29.0	333.2	18.90	0.98
TROPICANA PRODUCTS, INC	88	1110004	2	559.6	3,028.3	22.1				9.1	584.3	95.09	0.61
TROPICANA PRODUCTS, INC	89	1110004	3	559.6	3,028.3	22.1				9.1	584.3	95.09	0.61
TROPICANA PRODUCTS, INC	90	1110004	4	559.6	3,028.3	22.1	19.240	2.424	84.27	29.0	333.2	18.90	0.98
TROPICANA PRODUCTS, INC	91	1110004	6	559.6	3,028.3	22.1				13.7	505.4	12.77	0.61
ST LUCIE COUNTY HUMANE SOCIETY	86	1110041	2	566.8	3,033.0	22.2				9.4	1,255.4	7.62	0.55
RINKER MATERIALS CORP	92	1110051	1	559.8	3,028.0	22.5	0.022	0.003	0.10	13.7	298.7	8.84	0.24
RINKER MATERIALS CORP	93	1110051	2	559.8	3,028.0	22.5	0.210	0.026	0.92	3.7	298.2	3.66	1.07
RINKER MATERIALS CORP	94	1110051	3	559.8	3,028.0	22.5	0.072	0.009	0.10			2.44	0.43

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory (Page 3 of 4)

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	(g/s)	(tpy)	Stack Parameters Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
PRESTIGE GUNITE OF PORT CHARLOTTE, INC.	95	1110070	1	560.6	3,028.0	22.8							
PORT ST. LUCIE CREMATORY	97	1110066	1	566.7	3,022.5	30.5				4.6	908.2	2.44	0.52
FLORIDA POWER & LIGHT(PSL)	101	1110071	1	573.9	3,025.0	32.8	56.600	7.132	5.66	3.7	694.3	36.64	0.51
FLORIDA POWER & LIGHT(PSL)	102	1110071	2	573.9	3,025.0	32.8				4.0	838.7	56.66	0.15
FLORIDA POWER & LIGHT(PSL)	103	1110071	3	573.9	3,025.0	32.8	28.794	3.628	2.88				
TWIN OAKS PET CEMETARY	98	0930108	1	517.3	3,043.7	34.3	0.229	0.029	0.36	3.0	810.9	3.87	0.46
TWIN OAKS PET CEMETARY	99	0930108	2	517.3	3,043.7	34.3	0.260	0.033	0.41	4.6	560.9	6.03	0.46
TARMAC FLORIDA INC.	96	0090041	1	548.9	3,083.8	35.1	0.050	0.006	0.13	15.2	299.8	30.17	0.12
FLORIDA ROCK INDUSTRIES, INC.	105	1110072	3	547.5	3,013.5	35.6					298.2		
NORTH CYPRESS RESERVE	100	0090177	1	540.3	3,084.1	37.0	24.000	3.024	25.00	3.7	1,366.5		
AIR CURTAIN, INC.	104	0090119	1	535.3	3,085.1	39.6	16.000	2.016	20.00				
SOUTHDOWN, INCORPORATED	106	0090065	1	545.3	3,091.8	43.4	0.008	0.001	0.01	22.9	299.8	2.13	0.30
MATT STONE - EAST INC	107	0090121	1	545.1	3,092.4	44.0	0.080	0.010	0.01	11.3	299.8	4.57	0.30
RANGER CONSTRUCTION INDUSTRIES INC	108	0090122	1	544.6	3,092.5	44.2	11.930	1.503	12.40	9.1	394.3	51.51	0.82
OUTBOARD MARINE CORPORATION	110	0850108	1	572.5	3,009.4	44.8				12.2	310.9	9.69	0.61
AYCOCK FUNERAL HOME	111	0850015	2	573.5	3,008.4	46.1	0.520	0.066	2.28	7.3	865.9	5.49	0.52
GIBRALTER MAUSOLEUM CORP	109	0090045	1	537.3	3,092.9	46.2	0.610	0.077	0.95	4.9	644.3	13.41	0.40
MARTIN MEMORIAL HEALTH SYSTEMS	112	0850006	1	574.2	3,008.7	46.3	0.090	0.011	0.39	5.8	499.8	8.23	0.40
MARTIN MEMORIAL HEALTH SYSTEMS	113	0850006	5	574.2	3,008.7	46.3	0.090	0.011	0.39	5.8	499.8	8.23	0.40
WALLACE & WHITE FUN'L HOME & CREMATORY	114	0850106	1	573.4	3,007.5	46.9				4.9	644.3		6.10
RINKER MATERIALS CORP	115	0850003	1	574.1	3,007.3	47.4	7.730	0.974	33.85	3.7	259.3	24.08	0.46
RINKER MATERIALS CORP	116	0850003	2	574.1	3,007.3	47.4						2.44	0.43
CONTINENTAL CONCRETE	118	0850010	1	574.5	3,006.9	47.9	0.008	0.001	0.01	18.9	298.2		0.15
TARMAC FLORIDA	117	0930007	1	517.0	3,014.1	48.8				7.6	298.2	3.66	0.30
TARMAC FLORIDA, INC.	122	0850004	1	575.3	3,006.0	49.1	3.800	0.479	16.60	13.7	298.2	10.97	0.61
BUXTON FUNERAL HOME, INC.	119	0930102	1	516.8	3,013.7	49.2	0.226	0.028	0.35				
NORTHROP GRUMMAN CORP.	123	0850005	2	576.1	3,006.3	49.3				3.7	298.2		1.46
NORTHROP GRUMMAN CORP.	124	0850005	3	576.1	3,006.3	49.3				3.7	298.2		1.07
OKEECHOBEE ASPHALT	120	0930001	1	516.1	3,014.2	49.3	3.196	0.403	14.00	4.6	327.6	24.08	0.52
OKEECHOBEE ASPHALT	121	0930100	1	516.0	3,014.2	49.4				10.7	298.2	32.98	0.30
TURBO COMBUSTOR TECHNOLOGY	131	0850017	1	576.6	3,004.4	51.2				4.6	298.2		0.91
TURBO COMBUSTOR TECHNOLOGY	132	0850017	2	576.6	3,004.4	51.2							
TURBO COMBUSTOR TECHNOLOGY	133	0850017	3	576.6	3,004.4	51.2							
TURBO COMBUSTOR TECHNOLOGY	134	0850017	4	576.6	3,004.4	51.2	0.100	0.013	0.24				
ALEXANDER GUNITE, INC	137	0850018	1	577.2	3,003.9	51.9							
BRADSHAW MANUFACTURING	125	0090092	2	540.1	3,102.0	54.3	0.900	0.113	3.94	2.4	305.4	13.11	0.24
BRADSHAW MANUFACTURING	126	0090092	4	540.1	3,102.0	54.3	0.210	0.026	0.10	3.7	305.4	2.74	0.37
BRADSHAW MANUFACTURING	127	0090092	8	540.1	3,102.0	54.3	0.022	0.003	0.05	2.4	305.4	14.93	0.24
RINKER MATERIALS CORP	128	0090064	1	540.0	3,103.2	55.5	0.850	0.107	1.20	3.7	297.0	0.00	
RINKER MATERIALS CORP	129	0090064	2	540.0	3,103.2	55.5	0.320	0.040	0.45				
MORTON INTERNATIONAL	135	0090095	1	500.1	3,070.6	55.6	5.700	0.718	25.00	8.5	333.2	10.36	0.82
MORTON INTERNATIONAL	136	0090095	2	500.1	3,070.6	55.6	8.000	1.008	25.00	8.5	310.9	10.36	0.82
FAR RESEARCH INC	130	0090103	1	539.6	3,103.3	55.7	0.020	0.003	0.09	14.9	302.6	10.36	0.24
FLORIDA POWER & LIGHT MARTIN PLANT	146	0850001	1	542.7	2,992.7	56.8	557.900	70.295	2,437.00	152.1	420.9	21.03	7.99
FLORIDA POWER & LIGHT MARTIN PLANT	147	0850001	2	542.7	2,992.7	56.8	557.900	70.295	2,437.00	152.1	420.9	21.33	7.92
FLORIDA POWER & LIGHT MARTIN PLANT	148	0850001	3	542.7	2,992.7	56.8	18.000	2.268	100.00	64.9	410.9	18.59	6.10
FLORIDA POWER & LIGHT MARTIN PLANT	149	0850001	4	542.7	2,992.7	56.8	18.000	2.268	100.00	64.9	410.9	18.59	6.10

Table 6-2. FDEP Off-Property PM_{10} Emission Inventory (Page 4 of 4)

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	(g/s)	(tpy)	Stack Parameters Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
FLORIDA POWER & LIGHT MARTIN PLANT	150	0850001	5	542.7	2,992.7	56.8	18.000	2.268	100.00	64.9	410.9	18.59	6.10
FLORIDA POWER & LIGHT MARTIN PLANT	151	0850001	6	542.7	2,992.7	56.8	18.000	2.268	100.00	64.9	410.9	18.59	6.10
FLORIDA POWER & LIGHT MARTIN PLANT	152	0850001	7	542.7	2,992.7	56.8				12.8	593.2	11.28	0.61
FLORIDA POWER & LIGHT MARTIN PLANT	153	0850001	9	542.7	2,992.7	56.8				3.7	705.4	62.79	0.21
TAMPA FARM SERVICE, INC.	154	0850105	1	547.2	2,992.0	56.9				15.2	355.4	5.79	2.74
BAY STATE MILLING CO	155	0850012	1	547.4	2,991.7	57.3				6.4	298.2	7.01	0.70
BAY STATE MILLING CO	156	0850012	2	547.4	2,991.7	57.3	82.500	10.395	361.50	6.4	298.2	22.55	0.70
BAY STATE MILLING CO	157	0850012	3	547.4	2,991.7	57.3	82.500	10.395	361.50	7.9	298.2	8.23	1.10
BAY STATE MILLING CO	158	0850012	4	547.4	2,991.7	57.3	31.250	3.938	136.90	5.2	298.2	3.96	0.70
BAY STATE MILLING CO	159	0850012	7	547.4	2,991.7	57.3	0.007	0.001	0.03	20.1	298.2	3.05	0.30
BAY STATE MILLING CO	160	0850012	8	547.4	2,991.7	57.3	15.000	1.890	65.70	6.4	298.2	10.67	0.70
BAY STATE MILLING CO	161	0850012	9	547.4	2,991.7	57.3	1.500	0.189	6.60	19.8			0.21
BAY STATE MILLING CO	162	0850012	10	547.4	2,991.7	57.3	9.500	1.197	29.60	13.7	298.2	15.64	0.76
BAY STATE MILLING CO	163	0850012	11	547.4	2,991.7	57.3							
FL GAS TRANSMISSION	138	0090106	1	528.6	3,101.6	57.4	0.090	0.011	0.40	12.2	641.5	54.86	0.40
FL GAS TRANSMISSION	139	0090106	2	528.6	3,101.6	57.4	0.170	0.021	7.40	12.2	641.5	54.86	0.40
FL GAS TRANSMISSION	140	0090106	3	528.6	3,101.6	57.4				19.8	541.5	13.72	1.22
CAULKINS INDIANTOWN CITRUS CO	164	0850002	4	548.0	2,991.5	57.4	27.730	3.494	121.46	28.6	343.2	11.58	0.98
CAULKINS INDIANTOWN CITRUS CO	165	0850002	5	548.0	2,991.5	57.4	37.700	4.750	22.50	32.9			1.52
CAULKINS INDIANTOWN CITRUS CO	166	0850002	8	548.0	2,991.5	57.4	27.700	3.490	62.30	12.2	310.9	29.93	0.61
DICTAPHONE CORPORATION	141	0090100	1	536.0	3,104.5	57.7	0.060	0.008	0.06	7.9	1,033.2	2.44	0.30
DICTAPHONE CORPORATION	142	0090100	2	536.0	3,104.5	57.7				7.9	477.6	0.61	0.91
AMERICAN POWER TECH, INC	168	0850129	1	549.1	2,990.8	58.0	0.164	0.021	0.72				
INDIANTOWN COGENERATION, L.P.	169	0850102	1	547.7	2,990.7	58.2	61.600	7.762	270.00	150.9	333.2	28.41	4.88
INDIANTOWN COGENERATION, L.P.	170	0850102	3	547.7	2,990.7	58.2	1.400	0.176	0.70	64.0	449.8	26.70	1.52
INDIANTOWN COGENERATION, L.P.	171	0850102	4	547.7	2,990.7	58.2	3.460	0.436	15.09	9.1	298.2	12.37	0.85
INDIANTOWN COGENERATION, L.P.	172	0850102	5	547.7	2,990.7	58.2	1.170	0.147	5.11	53.3	338.7	9.78	0.91
INDIANTOWN COGENERATION, L.P.	173	0850102	6	547.7	2,990.7	58.2	0.100	0.013	0.45	16.8	298.2	7.77	0.30
BROWNLIE-MAXWELL FUNERAL HOME	143	0090019	1	538.8	3,106.0	58.5	0.090	0.011	0.39	4.9	644.3	4.27	0.52
RINKER MATERIALS INDIANTOWN	174	0850009	1	550.3	2,989.9	58.9	6.220	0.784	27.24				
RINKER MATERIALS INDIANTOWN	175	0850009	2	550.3	2,989.9	58.9							
RINKER MATERIALS INDIANTOWN	176	0850009	3	550.3	2,989.9	58.9							
SPACE COAST CREMATORY	144	0090115	1	537.9	3,107.2	59.9	0.087	0.011	0.17	6.1	866.5	5.49	0.52
ROCKWELL COLLINS INC	145	0090165	1	534.0	3,106.5	60.2					298.2		
AERC/MTI	167	0090124	1	529.5	3,107.5	62.6				7.6	299.8		5.49
PIONEER CONCRETE TILE	177	0850019	1	583.7	2,991.7	65.7	7.800	0.983	8.10	8.8	295.4	7.62	0.15
PIONEER CONCRETE TILE	178	0850019	2	583.7	2,991.7	65.7				8.8	295.4	7.62	0.15

Source: FDEP, 2000.

Table 6-3. Modeled FDEP Off-Property PM_{10} Emission Inventory

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	UTM Coordinates (km) Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	PM Emission Rates (g/s)	PM Emission Rates (tpy)	Stack Parameters Height (m)	Stack Parameters Temperature (K)	Stack Parameters Velocity (m/s)	Stack Parameters Diameter (m)
AMERICAN POWER TECH	7	0610080	1	550.71	3,051.11	2.4	0.796	0.100	3.48	17.4	394.3	16.18	0.91
AMERICAN POWER TECH	8	0610080	2	550.71	3,051.11	2.4	0.796	0.100	3.48	17.4	394.3	16.18	0.91
OCEAN SPRAY CRANBERRIES	1	0610021	1	550.62	3,051.29	2.6	0.110	0.014	0.48	9.1	491.5	7.62	0.64
OCEAN SPRAY CRANBERRIES	2	0610021	2	550.62	3,051.29	2.6	0.110	0.014	0.48	9.1	491.5	3.96	0.76
OCEAN SPRAY CRANBERRIES	3	0610021	3	550.62	3,051.29	2.6	0.110	0.014	0.48	9.1	491.5	17.07	0.46
OCEAN SPRAY CRANBERRIES	4	0610021	4	550.62	3,051.29	2.6	17.300	2.180	30.52	18.3	341.5	16.89	0.85
OCEAN SPRAY CRANBERRIES	5	0610021	5	550.62	3,051.29	2.6	8.560	1.079	26.46	11.0	310.9	9.36	0.91
OCEAN SPRAY CRANBERRIES	6	0610021	6	550.62	3,051.29	2.6	17.300	2.180	30.52	18.3	341.5	22.49	0.85
SHADY OAK PET CREMATORY	10	0610042	1	560.20	3,052.87	9.9	0.020	0.003	0.10	3.7	788.7	9.75	0.30
FLORIDA MINING & MATERIALS CORPORATION	16	0610035	1	560.80	3,052.70	10.3	0.023	0.003	0.10	9.1	299.8	19.20	0.46
FLORIDA MINING & MATERIALS CORPORATION	17	0610035	2	560.80	3,052.70	10.3	0.023	0.003	0.10	9.1	299.8	19.20	0.46
VERO BEACH CITRUS PACKERS	20	0610016	1	560.60	3,054.20	10.8	0.400	0.050	0.30	5.8	472.0	1.52	0.61
LOWTHER, THOMAS	11	0610077	1	558.60	3,057.02	11.0	0.430	0.054	1.90	5.5	922.0	4.94	0.52
RINKER/VERO BEACH	14	0610003	1	559.90	3,055.70	11.1	1.340	0.169	5.69	19.8	302.6	6.40	3.02
RINKER/VERO BEACH	15	0610003	2	559.90	3,055.70	11.1	0.320	0.040	0.08	9.1	299.8	19.20	0.15
RUSSELL CONCRETE	21	0610026	3	559.90	3,056.00	11.3	0.078	0.010	0.04	13.4	297.0	7.92	0.18
THE PACKERS OF INDIAN RIVER, INC.	22	0610032	1	559.40	3,057.50	11.9	2.600	0.328	1.84	7.6	477.6	48.46	0.61
CITY OF VERO BEACH	23	0610029	1	561.40	3,056.50	12.8	14.000	1.764	76.70	61.0	415.9	32.15	1.07
CITY OF VERO BEACH	24	0610029	2	561.40	3,056.50	12.8	72.900	9.185	133.00	61.0	448.2	41.82	1.07
CITY OF VERO BEACH	25	0610029	3	561.40	3,056.50	12.8	41.000	5.166	224.50	61.0	445.4	20.91	1.83
CITY OF VERO BEACH	26	0610029	3	561.40	3,056.50	12.8	123.000	15.498	224.50	61.0	445.4	20.91	1.83
CITY OF VERO BEACH	27	0610029	4	561.40	3,056.50	12.8	68.500	8.631	300.00	61.0	412.6	23.68	2.13
CITY OF VERO BEACH	28	0610029	5	561.40	3,056.50	12.8	11.400	1.436	23.70	38.1	416.5	19.38	3.35
CITY OF VERO BEACH	29	0610029	5	561.40	3,056.50	12.8	2.500	0.315	23.70	38.1	416.5	19.38	3.35
INDIAN RIVER MEMORIAL HOSPITAL	31	0610017	3	559.80	3,059.40	13.6	0.050	0.006	0.22	2.1	477.6	7.01	0.40
INDIAN RIVER MEMORIAL HOSPITAL	32	0610017	5	559.80	3,059.40	13.6	0.900	0.113	3.90	7.6	477.6	7.01	0.40
ST LUCIE COUNTY INTL AIRPORT	42	1110042	1	561.90	3,040.00	13.8	0.228	0.029	0.50	8.5	1,255.4	4.57	0.30
RIVERFRONT GROVES	33	0610025	1	558.20	3,061.00	14.0	0.530	0.067	1.00	4.9	422.0	1.52	0.61
FLORIDA GAS TRANSMISSION	44	1110060	1	557.24	3,035.78	14.4	0.110	0.014	0.48	8.5	588.7	21.94	0.49
FLORIDA GAS TRANSMISSION	45	1110060	2	557.24	3,035.78	14.4	0.110	0.014	0.48	8.5	588.7	21.94	0.49
FLORIDA GAS TRANSMISSION	46	1110060	3	557.24	3,035.78	14.4	0.150	0.019	0.64	8.5	588.7	29.26	0.49
FLORIDA GAS TRANSMISSION	47	1110060	4	557.24	3,035.78	14.4	0.090	0.011	0.40	19.8	641.5	76.50	0.34
FLORIDA GAS TRANSMISSION	48	1110060	5	557.24	3,035.78	14.4	0.160	0.020	0.68	6.7	873.2	78.63	0.15
INDIAN RIVER PACKING CO	34	0610018	1	558.20	3,061.60	14.6	0.180	0.023	1.00	5.5	422.0	2.13	0.52
LEROY E SMITHS SONS	35	0610019	1	558.30	3,061.60	14.6	0.080	0.010	0.27	6.1	466.5	3.96	0.61
FELIX ASPHALT OF FLORIDA	36	0610001	1	557.00	3,062.50	14.9	9.340	1.177	19.89	9.1	299.8	2.53	1.19

Table 6-3. Modeled FDEP Off-Property PM_{10} Emission Inventory (Page 2 of 3)

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	(g/s)	(tpy)	Stack Parameters Height (m)	Temperature (K)	Velocity (m/s)	Diameter (m)
TARMAC AMERICA INC	37	0610038	1	557.00	3,062.50	14.9	0.080	0.010	0.09	9.1	299.8	8.84	0.15
AIRLITE PROCESSING CORP OF FLORIDA	40	0610002	2	557.00	3,065.20	17.4	3.590	0.452	15.72	3.7	469.3	21.33	0.46
GREENE RIVER PACKING	38	0610068	1	556.64	3,065.35	17.4	0.271	0.034		5.5	533.2	1.34	0.67
GREENE RIVER PACKING	39	0610068	2	556.64	3,065.35	17.4	0.060	0.008	0.24	5.5	477.6	10.55	0.30
NOVARTIS CROP PROTECTION, INC.	41	0610033	1	553.73	3,066.78	18.1	0.530	0.067	0.78	9.4	1,144.3	7.62	0.55
MARCONA OCEAN INDUSTRIES	53	1110029	1	566.14	3,037.70	18.6	20.000	2.520	43.80	6.1	560.9	20.12	0.61
HAISLEY-HOBBS FUNERAL HOME	55	1110050	1	563.69	3,034.39	19.1	0.190	0.024	0.00	6.1	755.4	3.57	0.51
FT PIERCE UTILITIES AUTHORITY	56	1110003	1	566.12	3,036.35	19.4	10.420	1.313	45.66	7.0	783.2	11.89	0.91
FT PIERCE UTILITIES AUTHORITY	57	1110003	2	566.12	3,036.35	19.4	10.420	1.313	45.66	7.0	783.2	11.89	0.91
FT PIERCE UTILITIES AUTHORITY	58	1110003	3	566.12	3,036.35	19.4	25.330	3.192	110.66	20.7	492.0	18.23	3.41
FT PIERCE UTILITIES AUTHORITY	59	1110003	4	566.12	3,036.35	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	60	1110003	4	566.12	3,036.35	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	61	1110003	4	566.12	3,036.35	19.4	0.400	0.050		45.1	435.9	10.97	1.52
FT PIERCE UTILITIES AUTHORITY	62	1110003	7	566.12	3,036.35	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	63	1110003	7	566.12	3,036.35	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	64	1110003	7	566.12	3,036.35	19.4	0.568	0.072		44.8	426.5	18.62	2.16
FT PIERCE UTILITIES AUTHORITY	65	1110003	8	566.12	3,036.35	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
FT PIERCE UTILITIES AUTHORITY	66	1110003	8	566.12	3,036.35	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
FT PIERCE UTILITIES AUTHORITY	67	1110003	8	566.12	3,036.35	19.4	0.945	0.119	16.00	45.7	440.9	25.48	2.44
YATES FUNERAL HOME	71	1110059	1	565.89	3,034.62	20.4	0.600	0.076	0.90	7.0	669.3	8.23	0.52
GRAVES BROTHERS CO	50	0610006	2	555.20	3,069.70	21.3	0.066	0.008	0.22	6.7	477.6	5.49	0.46
RANGER CONSTRUCTION INDUSTRIES INC	73	1110040	2	561.67	3,030.17	21.4	50.000	6.300	52.00	7.0	435.9	51.51	0.76
CONTINENTAL CONCRETE INC	72	1110061	1	562.29	3,030.51	21.4	0.200	0.025	0.30	15.8	298.2	19.20	0.21
CONTINENTAL CONCRETE INC.	75	1110001	1	561.43	3,029.96	21.4	1.270	0.160	4.38	17.7	298.2	7.62	0.15
SUN PURE LTD	77	1110018	7	562.43	3,030.48	21.5	30.570	3.852	61.14	29.0	333.2	10.06	1.46
SUN PURE LTD	80	1110018	11	562.43	3,030.48	21.5	21.540	2.714	43.08	6.1	310.9	31.33	0.52
DICKERSON FLORIDA, INC	81	1110010	3	562.24	3,030.36	21.5	12.550	1.581	21.34	7.9	400.9	24.90	1.25
LYKES AGRI SALES, INC.	84	1110065	1	562.80	3,030.50	21.7	0.170	0.021	0.32	1.8	352.6	51.75	0.08
TROPICANA PRODUCTS, INC	87	1110004	1	559.61	3,028.32	22.1	19.240	2.424	84.27	29.0	333.2	18.90	0.98
TROPICANA PRODUCTS, INC	90	1110004	4	559.61	3,028.32	22.1	19.240	2.424	84.27	29.0	333.2	18.90	0.98
RINKER MATERIALS CORP	92	1110051	1	559.78	3,027.98	22.5	0.022	0.003	0.10	13.7	298.7	8.84	0.24
RINKER MATERIALS CORP	93	1110051	2	559.78	3,027.98	22.5	0.210	0.026	0.92	3.7	298.2	3.66	1.07
RINKER MATERIALS CORP	94	1110051	3	559.78	3,027.98	22.5	0.072	0.009	0.10	3.7	298.2	2.44	0.43
FLORIDA POWER & LIGHT(PSL)	101	1110071	1	573.86	3,025.01	32.8	56.600	7.132	5.66	3.7	694.3	36.64	0.51
TWIN OAKS PET CEMETARY	98	0930108	1	517.27	3,043.72	34.3	0.229	0.029	0.36	3.0	810.9	3.87	0.46
TWIN OAKS PET CEMETARY	99	0930108	2	517.27	3,043.72	34.3	0.260	0.033	0.41	4.6	560.9	6.03	0.46

Table 6-3. Modeled FDEP Off-Property PM_{10} Emission Inventory (Page 3 of 3)

Company Name	ISC ID	Facility ID	EU ID	UTM Coordinates (km) Easting (km)	UTM Coordinates (km) Northing (km)	Distance From BHEC (km)	PM Emission Rates (lb/hr)	PM Emission Rates (g/s)	PM Emission Rates (tpy)	Stack Parameters Height (m)	Stack Parameters Temperature (K)	Stack Parameters Velocity (m/s)	Stack Parameters Diameter (m)
TARMAC FLORIDA INC.	96	0090041	1	548.90	3,083.80	35.1	0.050	0.006	0.13	15.2	299.8	30.17	0.12
SOUTHDOWN, INCORPORATED	106	0090065	1	545.30	3,091.80	43.4	0.008	0.001	0.01	22.9	299.8	2.13	0.30
MATT STONE - EAST INC	107	0090121	1	545.11	3,092.37	44.0	0.080	0.010	0.01	11.3	299.8	4.57	0.30
RANGER CONSTRUCTION INDUSTRIES INC	108	0090122	1	544.58	3,092.50	44.2	11.930	1.503	12.40	9.1	394.3	51.51	0.82
AYCOCK FUNERAL HOME	111	0850015	2	573.50	3,008.40	46.1	0.520	0.066	2.28	7.3	865.9	5.49	0.52
GIBRALTER MAUSOLEUM CORP	109	0090045	1	537.30	3,092.90	46.2	0.610	0.077	0.95	4.9	644.3	13.41	0.40
MARTIN MEMORIAL HEALTH SYSTEMS	112	0850006	1	574.23	3,008.67	46.3	0.090	0.011	0.39	5.8	499.8	8.23	0.40
MARTIN MEMORIAL HEALTH SYSTEMS	113	0850006	5	574.23	3,008.67	46.3	0.090	0.011	0.39	5.8	499.8	8.23	0.40
RINKER MATERIALS CORP	115	0850003	1	574.12	3,007.29	47.4	7.730	0.974	33.85	3.7	259.3	24.08	0.46
CONTINENTAL CONCRETE	118	0850010	1	574.45	3,006.89	47.9	0.008	0.001	0.01	18.9	298.2	19.20	0.15
TARMAC FLORIDA, INC.	122	0850004	1	575.25	3,005.97	49.1	3.800	0.479	16.60	13.7	298.2	10.97	0.61
OKEECHOBEE ASPHALT	120	0930001	1	516.09	3,014.21	49.3	3.196	0.403	14.00	4.6	327.6	24.08	0.52

Source: FDEP, 2000.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The ISCST3 dispersion model, screening mode, was used to assess each of the 22 CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 70-, and 60-percent]; four ambient temperatures [20, 59, 72, and 95°F]; and three alternative operating modes [CTG inlet air evaporative cooling, CTG steam power augmentation, and HRSG DB firing]) for each pollutant subject to the ambient impact analysis (NO_2, SO_2, PM/PM_{10}, CO, and H_2SO_4 mist). The worst-case operating modes identified by the ISCST3 screening mode model for each pollutant were then carried forward to the refined modeling for further analysis.

ISCST3 screening mode model runs employed the specific stack exit temperature and exhaust gas velocity appropriate for each operating case. A nominal emission rate of 1.0 g/s was used for each case; model results were then scaled to reflect the maximum emission rates for each pollutant.

Tables 7-1 through 7-5 provide ISCST3 model (screening mode) maximum 1-hour impacts for NO_2, SO_2, PM/PM_{10}, CO, and H_2SO_4 mist, respectively. Tables 7-1 through 7-5 indicate, for each operating case, the maximum emission rate for each CTG/HRSG, ISCST3 screening mode model result based on a nominal 1.0-g/s emission rate, emission rate scaling factor, scaled ISCST3 screening mode model result, and location of maximum impact.

As shown in the ISCST3 model (screening mode) summary tables, maximum 1-hour impacts are projected to occur under Case 20 operating conditions (i.e., 100-percent load, CTG inlet air evaporative cooling, CTG steam power augmentation, and HRSG duct burner firing) for all pollutants except PM/PM_{10}. Maximum PM/PM_{10} 1-hour impacts are projected to occur under Case 18 operating conditions (i.e., 100-percent load, CTG inlet air evaporative cooling, and HRSG duct burner firing). These worst-case operating cases were then further analyzed using the ISCST3 refined mode dispersion model.

Table 7-1. ISCST3 (Screening Mode) Model Results—NO_2 Impacts, Four CTGs

						NO_2			Location of Impact			
			Ambient	ISCT3	ISCT3				UTM Coordinate			
	Operating	Load	Temper-ature	Emission Rate (Per CTG)	Maximum 1-Hr Impact	Emission Rate	Emission Rate	Maximum 1-Hr Impact	X	Y	Distance from CTG2	Vector Direction from CTG2
Case	Scenario	(%)	(°F)	(g/sec)	($\mu g/m^3$)	(g/sec)	Ratio	($\mu g/m^3$)	(meter)	(meter)	(meter)	(°)
1	CTG	100	20	1.0	21.61	3.33	3.33	72.04	551,224.8	3,048,994.5	183	0
2	CTG + DB	100	20	1.0	21.50	3.85	3.85	82.85	551,224.8	3,048,994.5	183	0
3	CTG + PAG	100	20	1.0	20.73	3.49	3.49	72.40	551,224.8	3,048,994.5	183	0
4	CTG + PAG + DB	100	20	1.0	20.62	4.01	4.01	82.78	551,224.8	3,048,994.5	183	0
5	CTG	70	20	1.0	25.52	2.50	2.50	63.93	551,224.8	3,048,994.5	183	0
6	CTG	60	20	1.0	28.05	2.24	2.24	62.84	551,224.8	3,048,994.5	183	0
7	CTG	100	59	1.0	25.36	3.07	3.07	77.83	551,224.8	3,048,994.5	183	0
8	CTG	70	59	1.0	29.22	2.33	2.33	68.03	551,224.8	3,048,994.5	183	0
9	CTG	60	59	1.0	31.61	2.12	2.12	66.90	551,224.8	3,048,994.5	183	0
10	CTG	100	72	1.0	27.00	2.98	2.98	80.50	551,224.8	3,048,994.5	183	0
11	CTG + EC	100	72	1.0	26.87	3.00	3.00	80.59	551,224.8	3,048,994.5	183	0
12	CTG + EC + DB	100	72	1.0	26.75	3.51	3.51	93.92	551,224.8	3,048,994.5	183	0
13	CTG	70	72	1.0	30.56	2.26	2.26	69.00	551,224.8	3,048,994.5	183	0
14	CTG	60	72	1.0	32.99	2.05	2.05	67.50	551,224.8	3,048,994.5	183	0
15	CTG	100	95	1.0	30.37	2.80	2.80	85.19	551,224.8	3,048,994.5	183	0
16	CTG + PAG	100	95	1.0	29.30	2.98	2.98	87.35	551,224.8	3,048,994.5	183	0
17	CTG + EC	100	95	1.0	30.24	2.84	2.84	85.87	551,224.8	3,048,994.5	183	0
18	CTG + EC + DB	100	95	1.0	30.10	3.35	3.35	100.84	551,224.8	3,048,994.5	183	0
19	CTG + EC + PAG	100	95	1.0	29.04	3.02	3.02	87.59	551,224.8	3,048,994.5	183	0
20	**CTG + EC + PAG + DB**	**100**	**95**	**1.0**	**28.91**	**3.54**	**3.54**	**102.25**	**551,224.8**	**3,048,994.5**	**183**	**0**
21	CTG	70	95	1.0	33.53	2.15	2.15	72.17	551,224.8	3,048,994.5	183	0
22	CTG	60	95	1.0	35.88	1.92	1.92	69.00	551,224.8	3,048,994.5	183	0
							Maximum	**102.25**				

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PAG = steam power augmentation.

Source: ECT, 2000.

Table 7-2. ISCST3 (Screening Mode) Model Results—SO_2 Impacts, Four CTGs

Case	Operating Scenario	Load (%)	Ambient Temper-ature (°F)	ISCT3 Emission Rate (Per CTG) (g/sec)	ISCT3 Maximum 1-Hr Impact (μg/m^3)	SO_2 Emission Rate (g/sec)	SO_2 Emission Rate Ratio	SO_2 Maximum 1-Hr Impact (μg/m^3)	Location of Impact: UTM Coordinate X (meter)	Location of Impact: UTM Coordinate Y (meter)	Location of Impact: Distance from CTG2 (meter)	Location of Impact: Vector Direction from CTG2 (°)
1	CTG	100	20	1.0	21.61	1.09	1.09	23.45	551,224.8	3,048,994.5	183	0
2	CTG + DB	100	20	1.0	21.50	1.23	1.23	26.50	551,224.8	3,048,994.5	183	0
3	CTG + PAG	100	20	1.0	20.73	1.14	1.14	23.59	551,224.8	3,048,994.5	183	0
4	CTG + PAG + DB	100	20	1.0	20.62	1.29	1.29	26.52	551,224.8	3,048,994.5	183	0
5	CTG	70	20	1.0	25.52	0.81	0.81	20.64	551,224.8	3,048,994.5	183	0
6	CTG	60	20	1.0	28.05	0.73	0.73	20.45	551,224.8	3,048,994.5	183	0
7	CTG	100	59	1.0	25.36	1.00	1.00	25.35	551,224.8	3,048,994.5	183	0
8	CTG	70	59	1.0	29.22	0.75	0.75	21.98	551,224.8	3,048,994.5	183	0
9	CTG	60	59	1.0	31.61	0.69	0.69	21.82	551,224.8	3,048,994.5	183	0
10	CTG	100	72	1.0	27.00	0.97	0.97	26.12	551,224.8	3,048,994.5	183	0
11	CTG + EC	100	72	1.0	26.87	0.97	0.97	26.19	551,224.8	3,048,994.5	183	0
12	CTG + EC + DB	100	72	1.0	26.75	1.12	1.12	30.02	551,224.8	3,048,994.5	183	0
13	CTG	70	72	1.0	30.56	0.73	0.73	22.36	551,224.8	3,048,994.5	183	0
14	CTG	60	72	1.0	32.99	0.67	0.67	22.07	551,224.8	3,048,994.5	183	0
15	CTG	100	95	1.0	30.37	0.91	0.91	27.67	551,224.8	3,048,994.5	183	0
16	CTG + PAG	100	95	1.0	29.30	0.97	0.97	28.44	551,224.8	3,048,994.5	183	0
17	CTG + EC	100	95	1.0	30.24	0.92	0.92	27.87	551,224.8	3,048,994.5	183	0
18	CTG + EC + DB	100	95	1.0	30.10	1.07	1.07	32.20	551,224.8	3,048,994.5	183	0
19	CTG + EC + PAG	100	95	1.0	29.04	0.98	0.98	28.51	551,224.8	3,048,994.5	183	0
20	**CTG + EC + PAG + DB**	**100**	**95**	**1.0**	**28.91**	**1.13**	**1.13**	**32.66**	**551,224.8**	**3,048,994.5**	**183**	**0**
21	CTG	70	95	1.0	33.53	0.70	0.70	23.40	551,224.8	3,048,994.5	183	0
22	CTG	60	95	1.0	35.88	0.63	0.63	22.52	551,224.8	3,048,994.5	183	0
							Maximum	32.66				

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PAG = steam power augmentation.

Source: ECT, 2000.

Table 7-3. ISCST3 (Screening Mode) Model Results—PM/PM_{10} Impacts, Four CTGs

						PM/PM_{10}			Location of Impact			
Case	Operating Scenario	Load (%)	Ambient Temper-ature (°F)	ISCT3 Emission Rate (Per CTG) (g/sec)	ISCT3 Maximum 1-Hr Impact (μg/m^3)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum 1-Hr Impact (μg/m^3)	UTM Coordinate X (meter)	UTM Coordinate Y (meter)	Distance from CTG2 (meter)	Vector Direction from CTG2 (°)
1	CTG	100	20	1.0	21.61	2.40	2.40	51.81	551,224.8	3,048,994.5	183	0
2	CTG + DB	100	20	1.0	21.50	3.25	3.25	69.85	551,224.8	3,048,994.5	183	0
3	CTG + PAG	100	20	1.0	20.73	2.41	2.41	49.98	551,224.8	3,048,994.5	183	0
4	CTG + PAG + DB	100	20	1.0	20.62	3.28	3.28	67.55	551,224.8	3,048,994.5	183	0
5	CTG	70	20	1.0	25.52	1.98	1.98	50.45	551,224.8	3,048,994.5	183	0
6	CTG	60	20	1.0	28.05	1.74	1.74	48.89	551,224.8	3,048,994.5	183	0
7	CTG	100	59	1.0	25.36	2.24	2.24	56.76	551,224.8	3,048,994.5	183	0
8	CTG	70	59	1.0	29.22	1.86	1.86	54.40	551,224.8	3,048,994.5	183	0
9	CTG	60	59	1.0	31.61	1.66	1.66	52.39	551,224.8	3,048,994.5	183	0
10	CTG	100	72	1.0	27.00	2.15	2.15	58.18	551,224.8	3,048,994.5	183	0
11	CTG + EC	100	72	1.0	26.87	2.17	2.17	58.29	551,224.8	3,048,994.5	183	0
12	CTG + EC + DB	100	72	1.0	26.75	2.99	2.99	80.05	551,224.8	3,048,994.5	183	0
13	CTG	70	72	1.0	30.56	1.81	1.81	55.20	551,224.8	3,048,994.5	183	0
14	CTG	60	72	1.0	32.99	1.61	1.61	53.26	551,224.8	3,048,994.5	183	0
15	CTG	100	95	1.0	30.37	1.99	1.99	60.43	551,224.8	3,048,994.5	183	0
16	CTG + PAG	100	95	1.0	29.30	2.00	2.00	58.72	551,224.8	3,048,994.5	183	0
17	CTG + EC	100	95	1.0	30.24	2.00	2.00	60.62	551,224.8	3,048,994.5	183	0
18	**CTG + EC + DB**	**100**	**95**	**1.0**	**30.10**	**2.82**	**2.82**	**84.75**	**551,224.8**	**3,048,994.5**	**183**	**0**
19	CTG + EC + PAG	100	95	1.0	29.04	2.02	2.02	58.65	551,224.8	3,048,994.5	183	0
20	CTG + EC + PAG + DB	100	95	1.0	28.91	2.85	2.85	82.25	551,224.8	3,048,994.5	183	0
21	CTG	70	95	1.0	33.53	1.71	1.71	57.34	551,224.8	3,048,994.5	183	0
22	CTG	60	95	1.0	35.88	1.53	1.53	54.86	551,224.8	3,048,994.5	183	0
							Maximum	84.75				

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PAG = steam power augmentation.

Source: ECT, 2000.

Table 7-4. ISCST3 (Screening Mode) Model Results—CO Impacts, Four CTGs

Case	Operating Scenario	Load (%)	Ambient Temper-ature (°F)	ISCT3 Emission Rate (Per CTG) (g/sec)	ISCT3 Maximum 1-Hr Impact ($\mu g/m^3$)	CO Emission Rate (g/sec)	CO Emission Rate Ratio	CO Maximum 1-Hr Impact ($\mu g/m^3$)	Location of Impact: UTM Coordinate X (meter)	Location of Impact: UTM Coordinate Y (meter)	Location of Impact: Distance from CTG2 (meter)	Location of Impact: Vector Direction from CTG2 (°)
1	CTG	100	20	1.0	21.61	5.80	5.80	125.24	551,224.8	3,048,994.5	183	0
2	CTG + DB	100	20	1.0	21.50	9.44	9.44	202.86	551,224.8	3,048,994.5	183	0
3	CTG + PAG	100	20	1.0	20.73	15.25	15.25	316.04	551,224.8	3,048,994.5	183	0
4	CTG + PAG + DB	100	20	1.0	20.62	24.35	24.35	502.14	551,224.8	3,048,994.5	183	0
5	CTG	70	20	1.0	25.52	4.41	4.41	112.55	551,224.8	3,048,994.5	183	0
6	CTG	60	20	1.0	28.05	19.53	19.53	547.83	551,224.8	3,048,994.5	183	0
7	CTG	100	59	1.0	25.36	5.42	5.42	137.39	551,224.8	3,048,994.5	183	0
8	CTG	70	59	1.0	29.22	4.03	4.03	117.80	551,224.8	3,048,994.5	183	0
9	CTG	60	59	1.0	31.61	18.52	18.52	585.41	551,224.8	3,048,994.5	183	0
10	CTG	100	72	1.0	27.00	5.17	5.17	139.50	551,224.8	3,048,994.5	183	0
11	CTG + EC	100	72	1.0	26.87	5.29	5.29	142.22	551,224.8	3,048,994.5	183	0
12	CTG + EC + DB	100	72	1.0	26.75	8.93	8.93	238.95	551,224.8	3,048,994.5	183	0
13	CTG	70	72	1.0	30.56	4.03	4.03	123.21	551,224.8	3,048,994.5	183	0
14	CTG	60	72	1.0	32.99	17.89	17.89	590.24	551,224.8	3,048,994.5	183	0
15	CTG	100	95	1.0	30.37	4.91	4.91	149.25	551,224.8	3,048,994.5	183	0
16	CTG + PAG	100	95	1.0	29.30	12.98	12.98	380.25	551,224.8	3,048,994.5	183	0
17	CTG + EC	100	95	1.0	30.24	4.91	4.91	148.58	551,224.8	3,048,994.5	183	0
18	CTG + EC + DB	100	95	1.0	30.10	8.56	8.56	257.52	551,224.8	3,048,994.5	183	0
19	CTG + EC + PAG	100	95	1.0	29.04	13.23	13.23	384.16	551,224.8	3,048,994.5	183	0
20	**CTG + EC + PAG + DB**	**100**	**95**	**1.0**	**28.91**	**22.33**	**22.33**	**645.60**	**551,224.8**	**3,048,994.5**	**183**	**0**
21	CTG	70	95	1.0	33.53	3.78	3.78	126.75	551,224.8	3,048,994.5	183	0
22	CTG	60	95	1.0	35.88	16.76	16.76	601.36	551,224.8	3,048,994.5	183	0
							Maximum	645.60				

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PAG = steam power augmentation.

Source: ECT, 2000.

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Table 7-5. ISCST3 (Screening Mode) Model Results—H_2SO_4 Impacts, Four CTGs

Case	Operating Scenario	Load (%)	Ambient Temper-ature (°F)	ISCT3 Emission Rate (Per CTG) (g/sec)	ISCT3 Maximum 1-Hr Impact (μg/m³)	H_2SO_4 Emission Rate (g/sec)	H_2SO_4 Emission Rate Ratio	H_2SO_4 Maximum 1-Hr Impact (μg/m³)	Location of Impact: UTM Coordinate X (meter)	Location of Impact: UTM Coordinate Y (meter)	Location of Impact: Distance from CTG2 (meter)	Location of Impact: Vector Direction from CTG2 (°)
1	CTG	100	20	1.0	21.61	0.20	0.20	4.31	551,224.8	3,048,994.5	183	0
2	CTG + DB	100	20	1.0	21.50	0.23	0.23	4.87	551,224.8	3,048,994.5	183	0
3	CTG + PAG	100	20	1.0	20.73	0.21	0.21	4.34	551,224.8	3,048,994.5	183	0
4	CTG + PAG + DB	100	20	1.0	20.62	0.24	0.24	4.87	551,224.8	3,048,994.5	183	0
5	CTG	70	20	1.0	25.52	0.15	0.15	3.79	551,224.8	3,048,994.5	183	0
6	CTG	60	20	1.0	28.05	0.13	0.13	3.76	551,224.8	3,048,994.5	183	0
7	CTG	100	59	1.0	25.36	0.18	0.18	4.66	551,224.8	3,048,994.5	183	0
8	CTG	70	59	1.0	29.22	0.14	0.14	4.04	551,224.8	3,048,994.5	183	0
9	CTG	60	59	1.0	31.61	0.13	0.13	4.01	551,224.8	3,048,994.5	183	0
10	CTG	100	72	1.0	27.00	0.18	0.18	4.80	551,224.8	3,048,994.5	183	0
11	CTG + EC	100	72	1.0	26.87	0.18	0.18	4.81	551,224.8	3,048,994.5	183	0
12	CTG + EC + DB	100	72	1.0	26.75	0.21	0.21	5.52	551,224.8	3,048,994.5	183	0
13	CTG	70	72	1.0	30.56	0.13	0.13	4.11	551,224.8	3,048,994.5	183	0
14	CTG	60	72	1.0	32.99	0.12	0.12	4.06	551,224.8	3,048,994.5	183	0
15	CTG	100	95	1.0	30.37	0.17	0.17	5.08	551,224.8	3,048,994.5	183	0
16	CTG + PAG	100	95	1.0	29.30	0.18	0.18	5.23	551,224.8	3,048,994.5	183	0
17	CTG + EC	100	95	1.0	30.24	0.17	0.17	5.12	551,224.8	3,048,994.5	183	0
18	CTG + EC + DB	100	95	1.0	30.10	0.20	0.20	5.92	551,224.8	3,048,994.5	183	0
19	CTG + EC + PAG	100	95	1.0	29.04	0.18	0.18	5.24	551,224.8	3,048,994.5	183	0
20	**CTG + EC + PAG + DB**	**100**	**95**	**1.0**	**28.91**	**0.21**	**0.21**	**6.00**	**551,224.8**	**3,048,994.5**	**183**	**0**
21	CTG	70	95	1.0	33.53	0.13	0.13	4.30	551,224.8	3,048,994.5	183	0
22	CTG	60	95	1.0	35.88	0.12	0.12	4.14	551,224.8	3,048,994.5	183	0
							Maximum	6.00				

Note: Case producing the highest impact is shown in bold type.
CTG = combustion turbine generator.
EC = evaporative cooler.
DB = duct burner.
PAG = steam power augmentation.

Source: ECT, 2000.

7.2 MAXIMUM FACILITY IMPACTS AND SIGNIFICANT IMPACT AREAS

The refined ISCST3 model was used to model the operating cases identified by the ISCST3 screening mode model to cause maximum impacts. ISCST3 refined mode model results for each year of meteorology evaluated (1987 to 1991) are summarized on Table 7-6 (annual NO_2 impacts), Table 7-7 (annual SO_2 impacts), Table 7-8 (24-hour SO_2 impacts), Table 7-9 (3-hour SO_2 impacts), Table 7-10 (annual PM_{10} impacts), Table 7-11 (24-hour PM/PM_{10} impacts), Table 7-12 (1-hour CO impacts), and Table 7-13 (8-hour CO impacts).

Tables 7-6 through 7-13 demonstrate that BHEC Project impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2, with the exception of PM_{10}. Table 7-14 provides a summary of maximum BHEC Project impacts and PSD significant impact levels. Comparisons of BHEC emission source impacts to the national and state AAQS are also provided in Table 7-14.

7.3 NAAQS ANALYSIS

An assessment of BHEC impacts, together with other sources within 53 km, was performed for comparison to the annual and 24-hour average PM_{10} NAAQS. The modeled emission inventory included the four BHEC CTG/HRSG units (operating under Case 18 conditions), north and south main cooling towers, and wastewater cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 53 km of the BHEC site. Conservatively, the PM emission rates provided by FDEP were assumed to be equal to PM_{10} emission rates. This approach is conservative; i.e., will over-estimate PM_{10} impacts, because PM_{10} emissions are a subset of PM emissions. For many emission sources, a substantial portion of PM emissions are larger in size than PM_{10} and, therefore, would not need to be included in the air quality analysis of PM_{10} impacts.

The receptor grids for the refined NAAQS analysis consisted of those individual receptors with significant impacts due to BHEC emission sources for each year of meteorology

Table 7-6. ISCST3 Model Results—Maximum Annual Average NO_2 Impacts (Case 20)

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
Unadjusted ISCST3 Impact (μg/m^3)[1]	0.20	0.13	0.23	**0.27**	0.22
Emission Rate Scaling Factor[2]	3.54	3.54	3.54	**3.54**	3.54
Tier 1 ISCST3 Impact (μg/m^3)[3]	0.71	0.44	0.83	**0.96**	0.77
Tier 2 ISCST3 Impact (μg/m^3)[4]	0.53	0.33	0.62	**0.72**	0.58
PSD Significant Impact (μg/m^3)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	53.0	33.3	62.2	**72.3**	57.8
Receptor UTM Easting (m)	551,016.1	551,016.1	551,016.1	**551,016.1**	551,016.1
Receptor UTM Northing (m)	3,048,978.8	3,048,978.8	3,048,978.8	**3,048,978.8**	3,048,955.0
Distance From CTG2 (m)	267	267	267	**267**	252
Direction From CTG2 (Vector °)	309	309	309	**309**	305

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CTG/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CTG/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor (assume complete conversion of NO_x to NO_2).

[4] Tier 1 ISCST3 impact times USEPA national default NO_2/NO_x ratio of 0.75.

Source: ECT, 2000.

Table 7-7. ISCST3 Model Results—Maximum Annual Average SO_2 Impacts (Case 20)

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	0.20	0.13	0.23	**0.27**	0.22
Emission Rate Scaling Factor[2]	1.13	1.13	1.13	**1.13**	1.13
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	0.23	0.14	0.26	**0.31**	0.25
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	22.6	14.2	26.5	**30.8**	24.6
Receptor UTM Easting (m)	551,016.1	551,016.1	551,016.1	**551,016.1**	551,016.1
Receptor UTM Northing (m)	3,048,978.8	3,048,978.8	3,048,978.8	**3,048,978.8**	3,048,955.0
Distance From CTG2 (m)	267	267	267	**267**	252
Direction From CTG2 (Vector °)	309	309	309	**309**	305

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CTG/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CTG/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

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Table 7-8. ISCST3 Model Results—Maximum 24-Hour Average SO_2 Impacts (Case 20)

Maximum 24-Hour Impacts	1987	1988	1989	**1990**	1991
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	3.2	3.3	2.5	**4.2**	3.4
Emission Rate Scaling Factor[2]	1.13	1.13	1.13	**1.13**	1.13
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	3.6	3.7	2.9	**4.8**	3.8
PSD Significant Impact ($\mu g/m^3$)	5.0	5.0	5.0	**5.0**	5.0
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	72.1	73.9	57.5	**95.3**	76.0
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	13.0	13.0	13.0	**13.0**	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	**N**	N
Percent of PSD *de minimis* Ambient Impact (%)	27.7	28.4	22.1	**36.7**	29.2
Receptor UTM Easting (m)	551,001.8	551,075.9	551,075.9	**551,100.7**	551,125.5
Receptor UTM Northing (m)	3,048,567.8	3,048,994.5	3,048,994.5	**3,048,994.5**	3,048,994.5
Distance From CTG2 (m)	330	235	235	**221**	208
Direction From CTG2 (Vector °)	222	321	321	**326**	332
Date of Maximum Impact	11/1/87	11/22/88	6/15/89	**10/10/90**	3/29/91
Julian Date of Maximum Impact	305	327	166	**283**	88

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CTG/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CTG/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-9. ISCST3 Model Results—Maximum 3-Hour Average SO_2 Impacts (Case 20)

Maximum 3-Hour Impacts	1987	**1988**	1989	1990	1991
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	9.7	**13.7**	6.7	6.5	12.9
Emission Rate Scaling Factor[2]	1.13	**1.13**	1.13	1.13	1.13
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	11.0	**15.5**	7.5	7.3	14.5
PSD Significant Impact ($\mu g/m^3$)	25.0	**25.0**	25.0	25.0	25.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	44.0	**61.9**	30.1	29.4	58.1
Receptor UTM Easting (m)	551,224.8	**551,224.8**	551,175.1	551,100.7	551,249.6
Receptor UTM Northing (m)	3,048,994.5	**3,048,994.5**	3,048,994.5	3,048,994.5	3,048,994.5
Distance From CTG2 (m)	183	**183**	190	221	185
Direction From CTG2 (Vector °)	0	**0**	345	326	8
Date of Maximum Impact	01/22/87	**11/23/88**	2/21/89	10/10/90	3/3/91
Julian Date of Maximum Impact	22	**328**	52	283	62
Ending Hour of Maximum Impact	0900	**0600**	1800	1200	1500

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CTG/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CTG/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-10. ISCST3 Model Results—Maximum Annual Average PM/PM_{10} Impacts (Case 18)

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact ($\mu g/m^3$)	2.30	2.06	2.66	**2.76**	2.48
PSD Significant Impact ($\mu g/m^3$)	1.0	1.0	1.0	**1.0**	1.0
Exceed PSD Significant Impact (Y/N)	Y	Y	Y	**Y**	Y
Percent of PSD Significant Impact (%)	230.4	205.7	265.9	**276.1**	248.2
Receptor UTM Easting (m)	551,268.8	551,268.8	551,044.6	**551,044.6**	551,044.6
Receptor UTM Northing (m)	3,048,532.5	3,048,508.8	3,048,994.5	**3,048,994.5**	3,048,994.5
Distance From CTG2 (m)	282	306	256	**256**	256
Direction From CTG2 (Vector °)	171	172	316	**316**	316

Note: Maximum impact shown in bold type.

Source: ECT, 2000.

Table 7-11. ISCST3 Model Results—Maximum 24-Hour Average PM_{10} Impacts (Case 18)

Maximum 24-Hour Impacts	**1987**	1988	1989	1990	1991
ISCST3 Impact ($\mu g/m^3$)	**27.2**	26.3	23.7	23.0	21.6
PSD Significant Impact ($\mu g/m^3$)	**5.0**	5.0	5.0	5.0	5.0
Exceed PSD Significant Impact (Y/N)	**Y**	Y	Y	Y	Y
Percent of PSD Significant Impact (%)	**544.8**	526.7	473.1	460.4	431.7
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	**10.0**	10.0	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	**Y**	Y	Y	Y	Y
Percent of PSD *de minimis* Ambient Impact (%)	**272.4**	263.4	236.5	230.2	215.8
Receptor UTM Easting (m)	**551,268.8**	551,268.8	551,268.8	551,044.6	551,268.8
Receptor UTM Northing (m)	**3,048,627.8**	3,048,532.5	3,048,532.5	3,048,994.5	3,048,627.8
Distance From CTG2 (m)	**189**	282	282	256	189
Direction From CTG2 (Vector °)	**166**	171	171	316	166
Date of Maximum Impact	**8/12/87**	12/17/88	12/4/89	3/16/90	6/5/90
Julian Date of Maximum Impact	**224**	352	338	75	156

Note: Maximum impact shown in bold.

Source: ECT, 2000.

Table 7-12. ISCST3 Model Results—Maximum 1-Hour Average CO Impacts (Case 20)

Maximum 1-Hour Impacts	1987	1988	1989	1990	**1991**
Unadjusted ISCST3 Impact (μg/m^3)[1]	16.3	17.3	11.7	11.8	**23.5**
Emission Rate Scaling Factor[2]	22.3	22.3	22.3	22.3	**22.3**
Adjusted ISCST3 Impact (μg/m^3)[3]	363.5	385.3	261.5	263.7	**525.4**
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 (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	18.2	19.3	13.1	13.2	**26.3**
Receptor UTM Easting (m)	551,224.8	551,224.8	551,268.8	551,224.8	**551,249.6**
Receptor UTM Northing (m)	3,048,994.5	3,048,994.5	3,048,508.8	3,048,994.5	**3,048,994.5**
Distance From CTG2 (m)	183	183	306	183	**185**
Direction From CTG2 (Vector °)	0	0	172	0	**8**
Date of Maximum Impact	1/22/87	11/23/88	2/9/89	6/4/90	**3/3/91**
Julian Date of Maximum Impact	22	328	40	155	**62**
Ending Hour of Maximum Impact	0900	0500	1600	1600	**1400**

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-13. ISCST3 Model Results—Maximum 8-Hour Average CO Impacts (Case 20)

Maximum 8-Hour Impacts	1987	**1988**	1989	1990	1991
Unadjusted ISCST3 Impact ($\mu g/m^3$)[1]	5.0	**7.7**	4.3	5.7	7.2
Emission Rate Scaling Factor[2]	22.3	**22.3**	22.3	22.3	22.3
Adjusted ISCST3 Impact ($\mu g/m^3$)[3]	111.2	**171.3**	95.3	128.0	159.7
PSD Significant Impact ($\mu g/m^3$)	500.0	**500.0**	500.0	500.0	500.0
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	22.2	**34.3**	19.1	25.6	31.9
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 (Y/N)	N	**N**	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	19.3	**29.8**	16.6	22.3	27.8
Receptor UTM Easting (m)	551,300.0	**551,224.8**	551,100.7	551,100.7	551,268.8
Receptor UTM Northing (m)	3,049,000.0	**3,048,994.5**	3,048,994.5	3,048,994.5	3,048,953.0
Distance From CTG2 (m)	204	**183**	221	221	149
Direction From CTG2 (Vector °)	22	**0**	326	326	18
Date of Maximum Impact	2/16/87	**11/23/88**	4/5/89	10/10/90	3/3/91
Julian Date of Maximum Impact	47	**327**	95	283	62
Ending Hour of Maximum Impact	1600	**0800**	1600	1600	1600

Note: Maximum impact shown in bold type.

[1] Based on modeled emission rate of 1.0 g/s per CT/HRSG unit.

[2] Ratio of maximum emission rate (g/s) per CT/HRSG unit to modeled 1.0 g/s emission rate.

[3] Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 2000.

Table 7-14. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

A. BHEC Impacts Compared to PSD Significant Impacts

Pollutant	Averaging Time	Maximum Impact (μg/m^3)	Significant Impact (μg/m^3)	Exceed Significant Impact (Y/N)
NO_2	Annual	0.72	1.0	N
SO_2	Annual	0.31	1.0	N
	24-hour	4.8	5.0	N
	3-hour	15.5	25.0	N
PM_{10}	Annual	2.8	1.0	Y
	24-hour	27.2	5.0	Y
CO	8-hour	171.3	500	N
	1-hour	525.4	2,000	N

B. BHEC Impacts Compared to AAQS

Pollutant	Averaging Time	Maximum Impact (μg/m^3)	AAQS (μg/m^3)	Percent of AAQS (%)
NO_2	Annual	0.72	100	0.7
SO_2	Annual	0.31	80 (NAAQS)	0.4
			60 (FAAQS)	0.5
	24-hour*	3.6	365 (NAAQS	1.0
			260 (FAAQS)	1.4
	3-hour*	9.4	1,300	0.7
PM_{10}	Annual	2.8	50	5.2
	24-hour*	24.9	150	16.6
CO	8-hour*	97.8	10,000	1.0
	1-hour*	378.1	40,000	0.9

* Highest, second highest

Source: ECT, 2000.

(i.e., 1987—1991) and each averaging period (i.e., 24-hour and annual average). The results of the annual and 24-hour average PM_{10} NAAQS modeling are provided on Tables 7-15 and 7-16, respectively. This table demonstrates that BHEC emission source impacts, together with all other off-property PM emission sources and including background, are well below the annual and 24-hour average PM_{10} NAAQS.

The NAAQS impact analysis was conducted using conservative premises for background PM_{10} levels, off-property source PM_{10} emission rates, and BHEC cooling tower PM_{10} emission rates. The *highest* 24-hour and annual average PM_{10} values obtained from the FDEP PM_{10} monitoring site located in Fort Pierce, St. Lucie County for 1997 and 1998 were used as background. This approach results in an over-estimation of total impacts due to "double-counting"; i.e., a portion of the FDEP monitored ambient PM_{10} data would be expected to have been caused by the same PM_{10} emission sources which are also included in the modeled emission inventory. As noted above, all PM emission rates provided by FDEP for the off-property sources were conservatively assumed to be equal to PM_{10} emission rates.

More significantly, BHEC cooling tower PM_{10} emission rates were estimated using EPA AP-42 procedures. As noted, and emphasized in AP-42, these emission estimation procedures result in "conservatively high" PM_{10} emission rates. Analysis of the dispersion model PM_{10} results shows that a significant portion of the total BHEC impacts are due to the BHEC cooling towers.

Because of the conservative approach used in conducting the air quality analysis for PM_{10} NAAQS impacts, there is reasonable assurance that the BHEC emission sources will not cause nor contribute to an exceedance of the PM_{10} NAAQS.

7.4 PSD CLASS II INCREMENT ANALYSIS

An assessment of BHEC impacts, together with other sources within 53 km, was performed for comparison to the annual and 24-hour average PSD Class II PM_{10} increments. The modeled emission inventory included the four BHEC CTG/HRSG units (operating

Table 7-15. ISCST3 Model Results—Maximum Annual Average PM_{10} Impacts; NAAQS Analysis

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact ($\mu g/m^3$)	3.38	3.49	3.95	**4.00**	3.89
Background ($\mu g/m^3$)	19.0	19.0	19.0	**19.0**	19.0
Total Impact ($\mu g/m^3$)	22.4	22.5	22.9	**23.0**	22.9
NAAQS ($\mu g/m^3$)	50.0	50.0	50.0	**50.0**	50.0
Exceed NAAQS (Y/N)	N	N	N	**N**	N
Percent of NAAQS (%)	44.8	45.0	45.9	**46.0**	45.8
Receptor UTM Easting (m)	551,268.8	551,268.8	551,044.6	**551,044.6**	551,044.6
Receptor UTM Northing (m)	3,048,532.5	3,048,508.8	3,048,994.5	**3,048,994.5**	3,048,994.5
Distance From CTG2 (m)	282	306	256	**256**	256
Direction From CTG2 (Vector °)	171	172	316	**316**	316

Note: Maximum impact shown in bold.

Source: ECT, 2000.

Table 7-16. ISCST3 Model Results—High, Second Highest 24-Hour Average PM_{10} Impacts; NAAQS Analysis

High, Second Highest 24-Hour Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact ($\mu g/m^3$)	31.2	24.3	21.6	**32.9**	27.4
Background ($\mu g/m^3$)	45.0	45.0	45.0	**45.0**	45.0
Total Impact ($\mu g/m^3$)	76.2	69.3	66.6	**77.9**	72.4
NAAQS ($\mu g/m^3$)	150.0	150.0	150.0	**150.0**	150.0
Exceed NAAQS (Y/N)	N	N	N	**N**	N
Percent of NAAQS (%)	50.8	46.2	44.4	**51.9**	48.3
Receptor UTM Easting (m)	551,041.9	551,041.9	551,044.6	**549,718.6**	551,056.2
Receptor UTM Northing (m)	3,048,515.8	3,048,515.8	3,048,994.5	**3,050,901.0**	3,048,496.8
Distance From CTG2 (m)	347	347	256	**2,575**	356
Direction From CTG2 (Vector °)	212	212	316	**324**	208
Date of Maximum Impact	11/7/87	6/16/88	6/16/89	**10/9/90**	10/8/91
Julian Date of Maximum Impact	311	168	167	**282**	281

Note: Maximum impact shown in bold.

Source: ECT, 2000.

under Case 18 conditions), north and south main cooling towers, and wastewater cooling tower, and all other sources contained in the FDEP PM emission inventory retrieval that are located within 53 km of the BHEC site. The FDEP PM_{10} emission inventory did not identify the specific emission sources which consume PSD PM_{10} increment. Conservatively, *all* off-property PM_{10} emission sources located within 53 km of the BHEC site were assumed to consume PSD increment. In addition, the PM emission rates provided by FDEP were conservatively assumed to be equal to PM_{10} emission rates.

The receptor grids for the refined PSD Class II PM_{10} increment analysis consisted of the same receptors used for the NAAQS analysis. The results of the 24-hour and annual average PSD Class II PM_{10} increment modeling are provided in Table 7-17 and 7-18, respectively. With one exception, these tables demonstrate that maximum BHEC emission source impacts, together with all other PSD PM_{10} increment consuming emission sources, are below the 24-hour and annual average PSD Class II PM_{10} increments. For 1990 meteorology, total 24-hour impacts are predicted to be above the PSD Class II increment using the conservative modeling procedures described above.

The 24-hour average PM_{10} impacts were further analyzed for 1990 meteorology to identify the specific receptors and days which had projected impacts above the PSD Class II increment of 30.0 $\mu g/m^3$. This analysis shows that total impacts greater than the PSD Class II increments were limited to one receptor and one daily period. Modeling of the BHEC emission sources for this one receptor and one daily period demonstrates that the BHEC emission sources will have an insignificant contribution; i.e., the offsite PM emission sources comprised 98.6 percent of the total impact with the BHEC emission sources contributing 0.47 $\mu g/m^3$ of the 32.9 $\mu g/m^3$ total.

Similar to the NAAQS air quality analysis, the assessment of PSD Class II PM_{10} increment consumption was conducted using several conservative premises. As noted above, *all* off-property PM emission sources were assumed to consume PSD PM_{10} increment. In addition, the PM emission rates provided by FDEP for the off-property sources were assumed to be equal to PM_{10} emission rates. The same conservatively high PM_{10} emission

Table 7-17. ISCST3 Model Results—High, Second Highest 24-Hour Average PM_{10} Impacts; PSD Class II Increment Analysis

High, Second Highest 24-Hour Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact (μg/m^3)	26.0	22.7	23.4	**32.9**	24.8
PSD Class II Increment (μg/m^3)	30.0	30.0	30.0	**30.0**	30.0
Exceed PSD Class II Increment (Y/N)	N	N	N	**Y**	N
Percent of PSD Class II Increment (%)	86.5	75.6	78.1	**109.6**	82.8
Receptor UTM Easting (m)	551,041.9	551,268.8	551,268.8	**549,718.6**	551,268.8
Receptor UTM Northing (m)	3,048,515.8	3,048,508.8	3,048,532.5	**3,050,901.0**	3,048,485.5
Distance From CTG2 (m)	347	306	282	**2,575**	329
Direction From CTG2 (Vector °)	212	172	171	**324**	172
Date of Maximum Impact	11/7/87	6/16/88	6/16/89	**10/9/90**	10/8/91
Julian Date of Maximum Impact	311	168	167	**282**	281

Note: Maximum impact shown in bold.

Source: ECT, 2000.

Table 7-18. ISCST3 Model Results—Maximum Annual PM_{10} Impacts; PSD Class II Increment Analysis

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
ISCST3 Impact ($\mu g/m^3$)	3.38	3.49	3.95	**4.00**	3.89
PSD Class II Increment ($\mu g/m^3$)	17.0	17.0	17.0	**17.0**	17.0
Exceed PSD Class II Increment (Y/N)	N	N	N	**N**	N
Percent of PSD Class II Increment (%)	19.9	20.6	23.2	**23.5**	22.9
Receptor UTM Easting (m)	551,268.8	551,268.8	551,044.6	**551,044.6**	551,044.6
Receptor UTM Northing (m)	3,048,532.5	3,048,508.8	3,048,994.5	**3,048,994.5**	3,048,994.5
Distance From CTG2 (m)	282	306	256	**256**	256
Direction From CTG2 (Vector °)	171	172	316	**316**	316

Note: Maximum impact shown in bold.

Source: ECT, 2000.

rates used for the BHEC cooling towers in the NAAQS analysis were also used in the PSD Class II PM_{10} increment consumption analysis.

Because of the conservative approach used in conducting the air quality analysis for PM_{10} PSD Class II increment consumption, there is reasonable assurance that the BHEC emission sources will not cause nor contribute to an exceedance of the PSD Class II PM_{10} increments.

7.5 PSD CLASS I IMPACTS

The nearest PSD Class I area (Everglades National Park) is located approximately 205 km south of the Project site. The Chassahowitzka National Wildlife Refuge Class I area is situated approximately 240 km to the northwest of the Project site. The BHEC CTG/HRSG units will be fired exclusively with natural gas and will include SCR control technology for abatement of NO_x emissions. Accordingly, Class I impacts due to emissions from the facility will be negligible.

7.6 SULFURIC ACID MIST

The maximum 8- and 24-hour average ISCST3 model impacts were 7.7 and 4.2 $\mu g/m^3$, respectively, based on a 1.0 g/s emission rate. Using a maximum H_2SO_4 mist emission rate of 0.236 g/s, maximum 8- and 24-hour impacts are calculated to be 1.8 and 1.0 g/m^3, respectively.

7.7 CONCLUSIONS

Comprehensive dispersion modeling using the ISCST3 models demonstrates that BHEC emission sources will result in ambient air quality impacts that are:

- Below the PSD significant impact levels for all pollutants and all averaging periods with the exception of PM_{10}.
- Below the PSD *de-minimis* ambient impact levels for all pollutants and all averaging periods with the exception of PM_{10}.

Comprehensive dispersion modeling using the refined ISCST3 model demonstrates that BHEC emission sources, together with all off-property PM emission sources located within 53 km of the BHEC site and including background concentrations, will result in ambient air quality impacts that are:

- Below the NAAQS for PM_{10}; and
- Below the PSD Class II increment for PM_{10}.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring stations to the BHEC are located in Fort Pierce, St. Lucie County, approximately 18 km southeast of the project site. The FDEP monitoring stations in Fort Pierce monitor for PM_{10}, $PM_{2.5}$, and ozone. The nearest FDEP stations that monitor for NO_2 are located in West Palm Beach, approximately 102 km southeast of the Project site, and Palm Beach, approximately 118 km southeast of the project site. The West Palm Beach and Palm Beach NO_2 monitoring sites, both located in Palm Beach County, collected ambient data in 1997 and 1998, respectively. The nearest FDEP station that monitors for CO is located in West Palm Beach, approximately 102 km southeast of the project site. The nearest FDEP station that monitors for SO_2 is located in Riviera Beach, Palm Beach County, approximately 95 km southeast of the project site. The nearest FDEP station monitoring for lead is situated in Coconut Creek, Broward County, approximately 146 km southeast of the project site. Summaries of 1997 and 1998 ambient air quality data for these FDEP ambient air quality monitoring stations are provided in Tables 8-1 and 8-2.

8.2 PRECONSTRUCTION AMBIENT AIR QUALITY MONITORING EXEMPTION APPLICABILITY

As previously discussed in Section 4.2, PSD review may require continuous ambient air monitoring data to be collected in the area of the proposed source for pollutants emitted in significant amounts. Because several pollutants will be emitted from the BHEC in excess of their respective significant emission rates, preconstruction monitoring is required. However, the FDEP Rule 62-212.400(2)(e), F.A.C., provides for an exemption from the preconstruction monitoring requirement for sources with *de minimis* air quality impacts. The *de minimis* ambient impact levels were previously presented in Table 4-1. To assess the appropriateness of monitoring exemptions, dispersion modeling analyses were performed to determine the maximum pollutant concentrations caused by emissions from the proposed BHEC. The results of these analyses are presented in detail in Section 7.2. The following paragraphs

Table 8-1. Summary of 1997 FDEP Ambient Air Quality Data

Pollutant	Site Location: County	Site Location: City	Site No.	Location Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	St. Lucie	Ft. Pierce	12-111-0012	21 SE	24-Hr	Jan-Dec	61	35	35	35		150[1]
					Annual						17	50[2]
			12-111-0012	21 SE	24-Hr	Jan-Dec	56	41	38	41		150[1]
					Annual						18	50[2]
SO_2	Palm Beach	Riviera Beach	12-099-3004	138 SE	1-Hr	Jan-Dec	8,274	487	236			
					3-Hr			165	154			1,300[3]
					24-Hr			50	37			260[3]
					Annual						4	60[2]
NO_2	Palm Beach	West Palm Beach	4760-004-G01	104 SE	1-Hr	Jan-Dec	8,219	105	103			
					Annual						25	100[2]
CO	Palm Beach	West Palm Beach	4760-004-G01	104 SE	1-Hr	Jan-Dec	8,232	12,597	11,452			40,000[3]
					8-Hr			8,016	3,436			10,000[3]
O_3	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	8,670	166.9	166.9			235[4]
Lead	Broward	Coconut Creek	12-011-5005	144 SE	24-Hr							
						Jan-Mar	14				0.0	1.5[2]
						Apr-Jun	15				0.0	
						Jul-Sep	14				0.0	
						Oct-Dec	15				0.0	

[1] 99th percentile

[2] Arithmetic mean

[3] 2nd high

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

Source: FDEP, 1998 and 1999.
ECT, 2000.

Table 8-2. Summary of 1998 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	Location Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3)				
	County	City						1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	St. Lucie	Ft. Pierce	12-111-0012	21 SE	24-Hr	Jan-Dec	56	45	35	45		150[1]
					Annual						19	50[2]
SO_2	Palm Beach	Riviera Beach	12-099-3004	138 SE	1-Hr	Jan-Dec	8,299	528.8	41.9			
					3-Hr			178.0	31.4			1,300[3]
					24-Hr			23.6	10.5			260[3]
					Annual						2.6	60[2]
NO_2	Palm Beach	West Palm Beach	12-099-1004	104 SE	1-Hr	Jan-Dec	8,254	112.9	112.9			
					Annual						22.6	100[2]
CO	Palm Beach	West Palm Beach	12-099-1006	105 SE	1-Hr	Jan-Dec	8,476	6,184.0	6,069.5			40,000[3]
					8-Hr			3,435.6	3,435.6			10,000[3]
O_3	St. Lucie	Ft. Pierce	12-111-1002	15 SE	1-Hr	Jan-Dec	356	186.5	186.5			235[4]
Lead	Broward	Coconut Creek	12-011-5005	144 SE	24-Hr		52					
						Jan-Mar					0.01	1.5[2]
						Apr-Jun					0.03	
						Jul-Sep					0.02	
						Oct-Dec					0.01	

[1] 99th percentile

[2] Arithmetic mean

[3] 2nd high

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

Source: FDEP, 1998 and 1999.
ECT, 2000.

summarize the analyses results as applied to the preconstruction ambient air quality monitoring exemptions.

8.2.1 PM_{10}

The maximum 24-hour PM_{10} impact was predicted to be 27.2 micrograms per cubic meter ($\mu g/m^3$). This concentration is above the 10 $\mu g/m^3$ *de minimis* level. In accordance with EPA guidance (EPA, 1992a), representative, current (1997 and 1998) quality-assured ambient PM_{10} data collected at the FDEP's PM_{10} monitoring site located in Fort Pierce, St. Lucie County was used to satisfy the PSD pre-construction ambient air monitoring requirements for PM_{10}. A summary of the FDEP-monitored PM_{10} ambient air quality data is provided on Tables 8-1 and 8-2.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 171.3 $\mu g/m^3$. This concentration is below the 575-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption for CO is appropriate in accordance with the PSD regulations.

8.2.3 NO_2

The maximum annual NO_2 impact was predicted to be 0.7 $\mu g/m^3$. 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 SO_2

The maximum 24-hour SO_2 impact was predicted to be 4.8 $\mu g/m^3$. This concentration is below the 13-$\mu g/m^3$ *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for SO_2 in accordance with the FDEP PSD regulations.

8.2.5 OZONE

Preconstruction monitoring for ozone is required if potential VOC emissions from a project subject to PSD review exceed 100 tpy. Because potential VOC emissions from the BHEC will exceed this threshold, current (1997 and 1998) quality-assured ambient ozone data collected at the FDEP's ozone monitoring site located in Fort Pierce, St. Lucie County was used to satisfy the PSD pre-construction ambient air monitoring requirements for ozone.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impact analysis, required for projects subject to PSD review, evaluates project impacts pertaining to: (a) associated growth; (b) soils, vegetation, and wildlife; and (c) visibility impairment. Each of these topics is discussed in the following sections.

9.1 GROWTH IMPACT ANALYSIS

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

Impacts associated with construction of the BHEC and ancillary equipment will be minor. While not readily quantifiable, the temporary increase in vehicular miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The BHEC is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the Project are anticipated. When operational, the Project is projected to generate approximately 36 new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas fuel demand due to operation of the BHEC Project will have no major impact on local fuel markets. No significant air quality impacts due to associated industrial/commercial growth are expected.

9.2 IMPACTS ON SOIL, VEGETATION, AND WILDLIFE

Although any additional increases in pollutant levels resulting from a specific emissions source conceivably could have some impact on air quality related values (AQRVs), it is important to evaluate the level of any expected increase. At the BHEC, the highest predicted SO_2 concentration increases due to the power plant are a 3-hour concentration of 15.5 $\mu g/m^3$, a 24-hour concentration of 4.8 $\mu g/m^3$, and an annual average concentration of 0.31 $\mu g/m^3$. The predicted concentrations of other pollutants are equally low. For instance, the highest modeled annual average NO_2 concentration increase due to the power plant emissions is 0.72 $\mu g/m^3$. Based upon these small predicted concentration increases, no adverse effect on AQRVs is expected within the vicinity of the plant Site. This conclusion is based upon the following evaluation of possible effects of the target pollutants on soil, vegetation, and wildlife in the region.

9.2.1 IMPACTS ON SOIL

Emissions of SO_2 and NO_x have the potential to impact soils due to wet and dry deposition of these pollutants. Adsorption by soils of this deposition will result in a lowering of soil pH. Low soil pH will have an influence on most chemical and biological reactions in soil including the level and availability of most plant nutrients in the soil. SO_2 when absorbed by the soil, is primarily converted to sulfite and sulfate; however some may also be converted to organic sulfur. NO_x absorbed by the soil is likewise converted to nitrite and nitrates. Sulfates and nitrates caused by SO_2 and NO_x deposition on soil can have beneficial effects to soil if they are currently lacking. Based on the extremely low maximum incremental and total SO_2 and NO_x impacts predicted and the ambient acidic nature of the soils, no impacts to soils resources at the plant Site or the vicinity are expected.

9.2.2 IMPACTS ON VEGETATION

As described in Section 2.3.5 of the SCA, the vegetation on the proposed power plant Site consists of natural vegetation represented by pine flatwoods with scattered oaks and a palmetto understory, a small cabbage palm forest, a mixed hardwood wetland forest and a fresh water marsh. The land use in the immediate area surrounding the Project area is a combination of natural and agricultural vegetation and developed land. The natural vegetation in the immediate vicinity consists of pine flatwoods. Agricultural uses include active and abandoned citrus groves and pasturelands. The developed land includes I-95 to the west and southwest of the Site; a correctional institution, single-family residence, and lateral canals to the north; and a sprayfield and mobile home development to the east.

Potential impacts to vegetation from SO_2, acid rain, NO_x, and CO have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Vegetation damages are described as impacts, which result in foliar damage. Less apparent vegetation injury is described as a reduction in growth and/or productivity without visible damage as well as changes in secondary metabolites such as tannin and phenolic compounds. Vegetation damage often results from acute exposure to pollution (i.e., relatively high doses of relatively short time periods). Injury is also associated with prolonged exposures of vegetation to relatively low doses of pollutants (chronic exposure). Acute damages are usually manifested by internal physical damage to foliar tissues which have both functional and visible consequences. Chronic injuries are typically more associated with changes in physiological processes. The following discussion summarizes descriptions from the literature of the effects upon vegetation associated with the pollutants of concern with the proposed power plant project.

SO_2

Natural (ambient) background concentrations of SO_2 range between 0.28 and 2.8 $\mu g/m^3$ of SO_2 on a mean annual basis (Prinz and Brandt, 1985). The most common source of atmospheric SO_2 is the combustion of fossil fuels (Mudd and Kozlowski, 1975). Gaseous SO_2 primarily affects vegetation by diffusion through the stomata (Varshney and Garg, 1979). Small amounts of SO_2 may also be absorbed through the protective cuticle. Adverse effects upon plants from SO_2 are primarily due to impacts to photosynthetic processes. SO_2 can react with chlorophyll by causing bleaching or by phaeophytinization. This latter process constitutes a photosynthetic deactivation of the chlorophyll molecule. Acute damage due to SO_2 appears as marginal or intercostal areas of dead tissue, which at first cause leaves to appear water soaked (Barrett and Benedict, 1970). Chronic injuries are less apparent; the leaves remain turgid and continue to function at a reduced level. In more severe cases of chronic SO_2 exposure, there is some bleaching of the chlorophyll which appears as a mild chlorosis or yellowing of the leaf and/or a silvering or bronzing of the undersurface. Species which are categorized as sensitive to SO_2 emissions are those which show damage to at least 5 percent of the leaf area upon being exposed to 131 to 1,310 $\mu g/m^3$ SO_2 for a period of 8 hours (Jones *et al.*, 1974).

Researchers have conducted numerous studies to determine the effects of SO_2 exposure to a wide variety of selected plant species. A review of the literature demonstrates that the most sensitive vascular plants (e.g., white ash, sumacs, yellow poplar, goldenrods, legumes, blackberry, southern pine, red oak, ragweeds) exhibit visible injury to short-term

(3 hours) exposure to SO_2 concentrations ranging from 790 to 1,570 μg/m^3 (ibid.). Caribbean pine (*Pinus caribaea*) seedlings similar in ecology and appearance to slash pine (*Pinus elliotti*) exhibited up to 5 percent needle necrosis when exposed to 1,310 μg/m^3 SO_2 for 4 hours (Umbach and Davis, 1988). Citrus is reported as being more tolerant to SO_2 exposures, with visible injury appearing when SO_2 concentrations exceed 1,572 to 2,096 μg/m^3 for a 3-hour period (EPA, 1976). Native plant species common to the region are either tolerant (red maple, live oak, cypress, slash pine) or sensitive (bracken fern) to SO_2 exposures (Woltz and Howe, 1981; U.S. Department of Agriculture, 1972; EPA, 1976; Loomis and Padgett, 1973). Complicating generalizations regarding SO_2 injury is the observation that the genetic variability of native annual plants can result in the selection of SO_2-resistant strains in as little as 25 years (Westman *et al.*, 1985).

Because of relative low chlorophyll content and the absence of a protective covering of the cuticle common in the leaves of higher plants, nonvascular plants such as lichens and bryophytes are relatively more sensitive to SO_2 injury. This injury has been documented on those primitive plants at levels as low as 88 μg/m^3 (U.S. Department of Health, Education, and Welfare, 1971). Hart *et al.* (1976) showed that *Ramalina* spp., a lichen genus exhibited a reduction of carbon dioxide uptake and biomass gain at SO_2 exposures of 400 μg/m^3 for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 μg/m^3; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975).

The maximum total 3-hour average SO_2 concentrations for the BHEC is projected to be 15.5 μg/m^3. The maximum total predicted 24-hour average SO_2 concentration is 4.8 μg/m^3. Annually, the concentration is predicted to be 0.31 μg/m^3. All of these estimates are lower than doses known to cause vegetative injury.

H_2SO_4 Mist

Acidic precipitation or acid rain is coupled to the emissions of the pollutant SO_2 mainly formed during the burning of fossil fuels. This compound is oxidized in the atmosphere and dissolves in rain forming H_2SO_4 mist which falls as acidic precipitation (Ravera, 1989). Concentration data are not available, but H_2SO_4 mist has yielded necrotic spotting on the upper surfaces of leaves. (Middleton *et al.*, 1950).

Since the concentration of H_2SO_4 mist from the proposed BHEC facility is directly dependent upon the availability of SO_2 and SO_2 concentrations are predicted to be well below levels which have been documented as negatively affecting vegetation, no impacts from H_2SO_4 mist are expected. During the last decade, much attention has been focused on acid rain. Acidic deposition is an ecosystem-level problem that affects vegetation because of some alterations of soil conditions such as increased leaching of essential base cations or elevated concentration of aluminum in the soil water (Goldstein *et al.*, 1985). Although effects of acid rain in eastern North America have been well publicized (decline of confer forests in the Appalachians), documented detrimental effects of acid rain on Florida vegetation is lacking (Gholz, 1985; Charles, 1991).

NO_x

During combustion, atmospheric nitrogen is oxidized to NO and small amounts of NO_2 (Taylor *et al.*, 1975). The NO is photochemically oxidized to NO_2, which, in turn is subsequently consumed in the production of ozone and peroxyacetyl nitrate (PAN). The ozone and PAN products have deleterious effects upon vegetation as air pollutants; impacts to vegetation from NO_2 only occur where spillage releases high concentrations during short time periods (Taylor and MacLean, 1970). Spills of this sort will cause necrotic lesions in leaf tissue and excessive defoliation (MacLean *et al.*, 1968). Short-term (acute) exposures of NO_2 of less than 1,880 $\mu g/m^3$ for 1 hour have not caused adverse effects (Taylor *et al.*, 1975). The maximum annual average NO_2 concentrations for the BHEC is 0.72 $\mu g/m^3$. This is well below that reported to cause injury to vegetation.

Synergism (SO_2-NO_x)

Combinations of air pollutants, where individual components are present in concentrations below their respective thresholds for vegetation injury, may still affect vegetation. If the effects appear to be directly proportional to the sum of the component's concentrations, the effect is termed additive. If effects are in excess of those expected from the summation of the component's concentrations, the effects are termed synergistic.

Recalling that NO_2 emissions are implicated in vegetation impacts based upon conversion to phytotoxic ozone and PANs, the appropriate synergistic reactions involve SO_2-ozone and SO_2-PAN. Typically, injury thresholds for susceptible plants approximate the injury thresholds as reported for SO_2 previously (Reinert *et al.*, 1975).

CO

CO is not considered harmful to plants and is not known to be effectively taken up by plants (Bennett and Hill, 1975). Microorganisms within the soil appear to be a major sink for CO. No impacts to vegetation from CO are expected.

9.2.3 IMPACTS ON WILDLIFE

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

Based on a review of the limited literature on air pollutant effects on wildlife, it is unlikely that the levels of pollutants produced by this 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.

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 (ibid.). 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 (ibid.). According to Barker (1983) and Charles (1991), no evidence is currently available to clearly show that degradation of aquatic systems have occurred as a direct result of acid precipitation in Florida. The projected air emissions from the BHEC which contribute to formation of atmospheric acids are not predicted to significantly increase acid precipitation and are predicted to have no impact on wildlife.

In conclusion, it is unlikely that the projected air emission levels from the proposed power plant will have any measurable direct or indirect effects on wildlife using the Site or vicinity.

Visibility Impairment Potential

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the BHEC Project. Opacity of the Project CTG/HRSG unit exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the Project CTG/HRSGs will be low due to the exclusive use of pipeline quality natural gas. The BHEC will comply with all applicable FDEP requirements pertaining to visible emissions.

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ATTACHMENT A

APPLICATION FOR AIR PERMIT—
TITLE V SOURCE

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **Calpine Construction Finance Company, L.P.**	
2. Site Name: **Blue Heron Energy Center**	
3. Facility Identification Number: [✔] Unknown	
4. Facility Location: Street Address or Other Locator: **SW 74th Avenue** City: **5 Miles SW of Vero Beach** County: **Indian River** Zip Code:	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [ ] Yes [✔] No

Application Contact

1. Name and Title of Application Contact: **Tim Eves** **Director – Business Development**
2. Application Contact Mailing Address: Organization/Firm: **Calpine Eastern** Street Address: **Two Urban Center, Suite 600** City: **4890 W. Kennedy Blvd.** State: **FL** Zip Code: **33609**
3. Application Contact Telephone Numbers: Telephone: **(813) 637-3523** Fax: **(813) 637-3597**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	12-5-00
2. Permit Number:	0610082-001-AC
3. PSD Number (if applicable):	PSD-FL-309
4. Siting Number (if applicable):	PA 00-42

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number:____________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number:____________________

Operation permit number to be revised:____________________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected:____________________

[ ] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised:____________________

Reason for revision:____________________

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[✔] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1.	Name and Title of Owner/Authorized Representative or Responsible Official: **Robert Alff, Senior Vice President**
2.	Application Contact Mailing Address: Organization/Firm: **Calpine Construction Finance Company, L.P.** Street Address: **The Pilot House, 2nd Floor, Lewis Wharf** City: **Boston** State: **MA** Zip Code: **02110**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(617) 723-7200, Ext. 303** Fax: **(617) 723-7635**
4.	Owner/Authorized Representative or Responsible Official Statement: *I, the undersigned, am the owner or authorized representative*(check here [ ], if so) or the responsible official (check here [✔], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.* Robert K. Alff Signature 10/23/00 Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Thomas W. Davis** Registration Number: **36777**
2.	Professional Engineer Mailing Address: Organization/Firm: **Environmental Consulting & Technology, Inc.** Street Address: **3701 Northwest 98th Street** City: **Gainesville** State: **FL** Zip Code: **32606**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-0444** Fax: **(352) 332-6722**

4. 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.

If the purpose of this application is to obtain a Title V source 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 schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit 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.

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

Thomas W. Davis — 10/24/00

Signature — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	CTG/HRSG Unit No. 1	AC1A	N/A
002	CTG/HRSG Unit No. 2	AC1A	N/A
003	CTG/HRSG Unit No. 3	AC1A	N/A
004	CTG/HRSG Unit No. 4	AC1A	N/A
005	North Main Fresh Water Cooling Tower	AC1A	N/A
006	South Main Fresh Water Cooling Tower	AC1A	N/A
007	Wastewater Cooling Tower	AC1A	N/A

Application Processing Fee

Check one: [ ] Attached - Amount: $ ________ [✔] Not Applicable

Note: Application processing fee submitted pursuant to the FPPSA.

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Calpine Construction Finance Company, L.P. (Calpine) is proposing to construct and operate a nominal 1,080-MW electric power generating station 5 miles southwest of Vero Beach in Indian River County. The Blue Heron Energy Center (BHEC) will consist of four nominal 17-MW Siemens Westinghouse 501F combustion turbine generators (CTGs), four fired heat recovery steam generator (HRSGs), and two nominal 200-MW steam turbines (STs). The four CTG/HRSG units are designated as Units 1 through 4. The CTGs will be equipped with inlet combustion air evaporator coolers and will include provisions for steam power augmentation. The HRSGs will each be equipped with a duct burner (DB) rated at 289 MMBtu/hr heat input (HHV). The CTGs and HRSG DBs will be fired exclusively with pipeline quality natural gas. The CTGs will operate at loads between 60 and 100 percent and will each operate at a capacity factor up to 100 percent.** **The BHEC will also include two main (north and south), 9 cell, mechanical draft fresh water cooling towers and one, three cell, mechanical draft wastewater cooling tower.**
2. Projected or Actual Date of Commencement of Construction: **No later than January 2002**
3. Projected Date of Completion of Construction: **March 2004**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **551.2**	North (km): **3,048.7**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):	Longitude (DD/MM/SS):		
3. Governmental Facility Code: **0**	4. Facility Status Code: **C**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Tim Eves, Director Business – Development**
2. Facility Contact Mailing Address: Organization/Firm: **Calpine Eastern** Street Address: **Two Urban Center, Suite 600** City: **4890 W. Kennedy Blvd.** State: **FL** Zip Code: **33609**
3. Facility Contact Telephone Numbers: Telephone: **(813) 637-3523** Fax: **(813) 637-3597**

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [✔] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [ ] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [✔] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters):	

List of Applicable Regulations

Reference Attachment A-1.	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
NOX	**A**	**N/A**	**N/A**	**N/A**	
SO2	**A**	**N/A**	**N/A**	**N/A**	
CO	**A**	**N/A**	**N/A**	**N/A**	
PM10	**A**	**N/A**	**N/A**	**N/A**	
PM	**A**	**N/A**	**N/A**	**N/A**	
VOC	**A**	**N/A**	**N/A**	**N/A**	
SAM	**B**	**N/A**	**N/A**	**N/A**	

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1.	Area Map Showing Facility Location: [✔] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested
2.	Facility Plot Plan: [✔] Attached, Document ID: **Fig. 2-3** [ ] Not Applicable [ ] Waiver Requested
3.	Process Flow Diagram(s): [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
4.	Precautions to Prevent Emissions of Unconfined Particulate Matter: [✔] Attached, Document ID: **Att. A-2** [ ] Not Applicable [ ] Waiver Requested
5.	Fugitive Emissions Identification: [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
6.	Supplemental Information for Construction Permit Application: [✔] Attached, Document ID: [ ] Not Applicable **PSD Permit Application**
7.	Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

Not Applicable

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] Not Applicable
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:____________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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. Regulated or Unregulated Emissions Unit? (Check one)

[✔] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one Siemens Westinghouse 501F combustion turbine generator (CTG) having a nominal rating of 170 megawatts (MW) and one heat recovery steam generator (HRSG) equipped with a duct burner rated at 289 MMBtu/hr heat input (HHV). The CTG and HRSG DB will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number:
ID: **001 (CTG/HRSG Unit 1)**

[✔] No ID
[ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[✔]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **<u>NO_x Controls</u>** **Dry low-NO_x combustors – CTG** **Low-NO_x burners – HRSG DB** **Selective Catalytic Reduction (SCR)**
2. Control Device or Method Code(s): **025 (dry low-NO_x combustors and low-NO_x burners) and 065 (catalytic reduction)**

Emissions Unit Details

1. Package Unit: Manufacturer: **Siemens Westinghouse**	Model Number: **501F**
2. Generator Nameplate Rating: **170** MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	**1,760 (LHV)** mmBtu/hr		
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	24 hours/day		**7** days/week
	52 weeks/year		**8,760** hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is lower heating value (LHV) for the CTG at 100 percent load, 59°F, and without inlet air evaporative cooling or steam power augmentation (Case 7). CTG heat input will vary with load, ambient temperature, and optional use of inlet air evaporative cooling and steam power augmentation.** **Rated heat input for the DB is 260 MMBtu/hr (LHV).**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **CTG 1**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **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: **135** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **165** °F	9. Actual Volumetric Flow Rate: **971,235** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters): **Stack temperature and flow rate are at 100 percent load, 59°F ambient temperature, and without inlet air evaporative cooling, steam power augmentation, or duct burner firing (Case 7). Stack flow rate will vary with load, ambient temperature, and optional use of inlet air evaporative cooling, steam power augmentation, and duct burner firing.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Combustion turbine fired with pipeline quality natural gas.**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
4. Maximum Hourly Rate: **2.381**	5. Maximum Annual Rate: **20,857.6**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,050**
10. Segment Comment (limit to 200 characters): **Fuel heat content (Field 9) represents higher heating value (HHV).**		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
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 (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 – NOX	**025**	**065**	**EL**
2 – CO			**EL**
3 – PM			**EL**
4 – PM10			**EL**
5 – SO2			**EL**
6 – SAM			**EL**
7 – VOC			**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOX**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **31.9** lb/hour **112.1** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **31.9 lb/hr** Reference: **Siemens Westinghouse**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Siemens Westinghouse data for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 24.4 lb/hr (100 percent load and 59°F – Case 7) for 5,880 hrs/yr and 28.1 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **3.5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 20 (initial), NO_x CEMS**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Unit is also subject to less stringent NO_x limits of 40 CFR Part 60, Subpart GG (NSPS).**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **193.3** lb/hour **459.7** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **193.3 lb/hr** Reference: **Siemens Westinghouse**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on Siemens Westinghouse data for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 43.0 lb/hr (100 percent load and 59°F – Case 7) for 4,380 hrs/yr, 147.0 lb/hr (60 percent load and 59°F – Case 9) for 1,500 hrs/yr, and 177.3 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **46.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load without steam power augmentation or duct burner firing.**	

Allowable Emissions Allowable Emissions 2 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **15.6 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **74.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load without steam power augmentation and with duct burner firing.**	

Allowable Emissions Allowable Emissions 3 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: **25.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **121.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load with steam power augmentation and without duct burner firing.**	

Allowable Emissions Allowable Emissions 4 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: **38.5 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **193.2** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).** **Limit applicable at 100 percent load with steam power augmentation and with duct burner firing.**	

Allowable Emissions Allowable Emissions 5 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
7. Requested Allowable Emissions and Units: **50.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **155.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).** **Limit applicable at 60 to 70 percent load without steam power augmentation and without duct burner firing.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.0** lb/hour **84.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **26.0 lb/hr** Reference: **Siemens Westinghouse**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

Hourly emission rate based on Siemens Westinghouse data for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 17.8 lb/hr (100 percent load and 59°F – Case 7) for 5,880 hrs/yr and 22.6 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **26.0** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 9

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **26.0** lb/hour **84.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **26.0 lb/hr** Reference: **Siemens Westinghouse**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

Hourly emission rate based on Siemens Westinghouse data for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 17.8 lb/hr (100 percent load and 59°F – Case 7) for 5,880 hrs/yr and 22.6 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

PM emissions data represents "front- and back-half" particulate matter as measured by EPA Reference Methods 201 and 202. PM and PM_{10} emissions are assumed to be equal.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **26.0** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 9

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10.2** lb/hour **36.3** tons/year	4. Synthetically Limited? [✓]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10.2 lb/hr** Reference: **ECT – Mass Balance**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

(1.5 gr S/100 scf) x (2.381 x 10^6 ft^3/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 10.2 lb/hr SO_2

Annual emissions based on 7.9 lb/hr (100 percent load and 59°F – Case 7) for 5,880 hrs/yr and 9.0 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 gr S/100 scf**	4. Equivalent Allowable Emissions: **10.2** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
Fuel analysis for sulfur content

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).
Unit is also subject to less stringent fuel sulfur limits of 40 CFR Part 60, Subpart GG (NSPS).

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
**(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)**

Potential/Fugitive Emissions

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.9** lb/hour **6.7** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.9 lb/hr** Reference: **ECT**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):
Hourly emission rate based on 8.0% conversion of fuel S to SO_3 (CTG), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4 for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 1.46 lb/hr (100 percent load and 59°F – Case 7) for 5,880 hrs/yr and 1.65 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.5 gr S/100 scf**	4. Equivalent Allowable Emissions: **1.9** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
Fuel analysis for sulfur content

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.8** lb/hour **35.1** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **17.8 lb/hr** Reference: **Siemens Westinghouse**	7. Emissions Method Code: **2**

8. Calculation of Emissions (limit to 600 characters):

Hourly emission rate based on Siemens Westinghouse data for 100 percent load, 18°F ambient temperature, steam power augmentation, and duct burner firing (Case 4). Annual emissions based on 2.9 lb/hr (100 percent load and 59°F – Case 7) for 4,380 hrs/yr, 17.4 lb/hr (60 percent load and 59°F – Case 9) for 1,500 hrs/yr, and 177.3 lb/hr (100 percent load, 95°F, evaporative cooling, steam power augmentation, and duct burner firing – Case 20) for 2,880 hr/yr.

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Allowable Emissions Allowable Emissions 1 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.2 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **3.2** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
EPA Reference Method 18, 25, or 25A.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).

Allowable Emissions Allowable Emissions 2 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
8. Requested Allowable Emissions and Units: **3.4 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **9.0** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18, 25, or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load without steam power augmentation and with duct burner firing.**	

Allowable Emissions Allowable Emissions 3 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
9. Requested Allowable Emissions and Units: **1.2 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **3.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18, 25, or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load with steam power augmentation and without duct burner firing.**	

Allowable Emissions Allowable Emissions 4 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
10. Requested Allowable Emissions and Units: **6.6 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **17.7** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18, 25, or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 100 percent load with steam power augmentation and with duct burner firing.**	

Allowable Emissions Allowable Emissions 5 of 5

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
11. Requested Allowable Emissions and Units: **3.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **5.3** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Reference Method 18, 25, or 25A.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT). Limit applicable at 60 to 70 percent load without steam power augmentation and without duct burner firing.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [✔] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT).**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [✔] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Reference Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **Excess emissions resulting from startup, shutdown, or malfunction not-to-exceed 2 hours in any 24 hour period unless authorized by FDEP for a longer duration. Rule 62-210.700(1), F.A.C.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NOX**
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **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 2

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 (limit to 200 characters): **Required by 40 CFR Part 75 (Acid Rain Program).** **Specific CEMS information will be provided to FDEP when available.**	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [✔] Attached, Document ID: **Att. A-3** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities **To be provided** [ ] Attached, Document ID:________ [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

Not Applicable

11. Alternative Methods of Operation
    [ ] Attached, Document ID:________ [ ] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
    [ ] Attached, Document ID:________ [ ] Not Applicable

13. Identification of Additional Applicable Requirements
    [ ] Attached, Document ID:________ [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

    [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
    Attached, Document ID:________

    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
    Attached, Document ID:________

    [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
    Attached, Document ID:________

    [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
    Attached, Document ID:________

    [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
    Attached, Document ID:________

    [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
    Attached, Document ID:________

    [ ] Not Applicable

NOTE:

EMISSION UNITS CTG/HRSG UNITS 1 THROUGH 4 ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 001 (CTG/HRSG UNIT 1) IS ALSO APPLICABLE TO EU 002 (CTG/HRSG UNIT 2), EU 003 (CTG/HRSG UNIT 3), AND EU 004 (CTG/HRSG UNIT 4).

EMISSIONS UNIT INFORMATION SECTIONS 2 THROUGH 7 ARE IDENTICAL TO SECTION 1, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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. Regulated or Unregulated Emissions Unit? (Check one)

[ ] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
North main fresh water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

4. Emissions Unit Identification Number: [✔] No ID
ID: **005 (North Main Cooling Tower)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift eliminators**
2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: MW	
3. Incinerator Information: Dwell Temperature: °F Dwell Time: seconds Incinerator Afterburner Temperature: °F	

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		mmBtu/hr		
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate: **150,000 gal/min**				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum process rate (Field 3) is cooling tower water recirculation rate.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **NMT1 thru NMT9**		2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Cooling tower consists of nine 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: **62** feet	7. Exit Diameter: **33.0** feet
8. Exit Temperature: **106** °F	9. Actual Volumetric Flow Rate: **1,421,771** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters): **Cooling tower consists of 9 cells with 9 individual exhaust fans. Stack height, diameter, exit temperature, and flow rate provided in Fields 6 thru 9 are for each cell.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Fresh water cooling tower recirculation water flow rate.**		
2. Source Classification Code (SCC):	3. SCC Units: **Thousand gallons transferred**	
4. Maximum Hourly Rate: **9,000.0**	5. Maximum Annual Rate: **78,840,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
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 (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **12.3** lb/hour **53.9** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12.3 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(150,000 gal/min) x (0.002 gal/100 gal) x (8,200 lb PM/10^6 lb water) x (8.345 lb/gal water) x (60 min/hr) = 12.3 lb/hr PM** **(24.6 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 53.9 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions____of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.4** lb/hour **32.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **7.4 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(150,000 gal/min) x (0.002 gal/100 gal) x (8,200 lb PM/10^6 lb water) x (0.6 lb PM_{10} / lb PM) x (8.345 lb/gal water) x (60 min/hr) = 7.4 lb/hr PM** **(7.4 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 32.4 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION – Not Applicable
(Only Regulated Emissions Units 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:
6. Continuous Monitor Comment (limit to 200 characters):	

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 (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: ______ [✔] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:______ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:______ [ ] Previously submitted, Date:__________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:______ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:______ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:______ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:______ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

Not Applicable

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

NOTE:

THE NORTH AND MAIN COOLING TOWERS ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 005 (NORTH MAIN COOLING TOWER) IS ALSO APPLICABLE TO EU 006 (SOUTH MAIN COOLING TOWER).

EMISSIONS UNIT INFORMATION SECTIONS 2 THROUGH 7 ARE IDENTICAL TO SECTION 1, WITH THE EXCEPTION OF IDENTIFICATION NUMBERS.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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. Regulated or Unregulated Emissions Unit? (Check one)

[ ] 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.

4. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Wastewater water cooling tower. Tower is equipped with drift eliminators for control of PM/PM_{10} emissions.

4. Emissions Unit Identification Number: [✔] No ID
ID: **007 (Wastewater Cooling Tower)** [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C		**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Emissions Unit Control Equipment

8. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift eliminators**
2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:	
2. Generator Nameplate Rating: MW		
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:		°F seconds °F

Emissions Unit Control Equipment

8. Control Equipment/Method Description (Limit to 200 characters per device or method): **Drift eliminators**
2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit: Manufacturer:	Model Number:
2. Generator Nameplate Rating: MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:	mmBtu/hr			
2. Maximum Incineration Rate:	lb/hr		tons/day	
3. Maximum Process or Throughput Rate: **5,000 gal/min**				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
	24	hours/day	**7**	days/week
	52	weeks/year	**8,760**	hours/year
7. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum process rate (Field 3) is cooling tower water recirculation rate.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment A-1	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **WT1 thru WT3**	9. Emission Point Type Code: **3**

10. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Cooling tower consists of three cells.

11. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:

N/A

12. Discharge Type Code: **V**	6. Stack Height: **21** feet	7. Exit Diameter: **10.5** feet
8. Exit Temperature: **100** °F	9. Actual Volumetric Flow Rate: **198,653** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

Cooling tower consists of 3 cells with 3 individual exhaust fans. Stack height, diameter, exit temperature, and flow rate provided in Fields 6 thru 9 are for each cell.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Fresh water cooling tower recirculation water flow rate.**		
3. Source Classification Code (SCC):	3. SCC Units: **Thousand gallons transferred**	
6. Maximum Hourly Rate: **300.0**	7. Maximum Annual Rate: **2,628,000**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	10. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment ____ of ____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
3. Source Classification Code (SCC):	3. SCC Units:	
6. Maximum Hourly Rate:	7. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
11. Maximum % Sulfur:	12. Maximum % Ash:	13. Million Btu per SCC Unit:
14. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.3** lb/hour **5.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.3 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(5,000 gal/min) x (0.0005 gal/100 gal) x (104,280 lb PM/10^6 lb water) x (8.345 lb/gal water) x (60 min/hr) = 1.3 lb/hr PM** **(1.3 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 5.7 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.0** lb/hour **4.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.0 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(5,000 gal/min) x (0.0005 gal/100 gal) x (104,280 lb PM/10^6 lb water) x (0.8 lb PM_{10} / lb PM) x (8.345 lb/gal water) x (60 min/hr) = 1.0 lb/hr PM** **(1.0 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 4.6 ton/yr PM**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance (limit to 60 characters):	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

2. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance:	
7. Visible Emissions Comment (limit to 200 characters):	

Visible Emissions Limitation: Visible Emissions Limitation ____ of ____

2. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
6. Method of Compliance:	
7. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION – Not Applicable
(Only Regulated Emissions Units 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:
13. Continuous Monitor Comment (limit to 200 characters):	

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:
14. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [✔] Attached, Document ID: **Fig. 2-4** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID: _______ [✔] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [✔] Attached, Document ID: **Sect. 5.0** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [✔] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [✔] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [✔] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

Not Applicable

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [ ] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

ATTACHMENT A-1

REGULATORY APPLICABILITY ANALYSES

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

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

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Standards for Sulfur Dioxide	§60.333		CTG/HRSG Units 1-4	Establishes exhaust gas SO_2 limit of 0.015 percent by volume (at 15% O_2, dry) and maximum fuel sulfur content of 0.8 percent by weight.
Subpart GG - Standard of Performance for Stationary Gas Turbines				
Monitoring Requirements	§60.334(a)		CTG/HRSG Units 1-4	Requires continuous monitoring of fuel consumption and ratio of water to fuel being fired in the turbine. Monitoring system must be accurate to ±5.0 percent. Applicable to CTs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CTG/HRSG Units 1-4	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CTG/HRSG Units 1-4	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Cb, Cc, Cd, Ce, D, Da, Db, Dc, E, Ea, Eb, Ec, F, G, H, I, J, K, Ka, Kb, L, M, N, Na, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, AAa, BB, CC, DD, EE, HH, KK, LL, MM, NN, PP, QQ, RR, SS, TT, UU, VV, WW, XX, AAA, BBB, DDD, FFF, GGG, HHH, III, JJJ, KKK, LLL, NNN, OOO, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to the BHEC combined cycle CTG/HRSGs.
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants: Subparts A, B, C, D, E, F, H, I, J, K, L, M, N, O, P, Q, R, T, V, W, Y, BB, and FF		X		None of the listed NESHAPS' contain requirements which are applicable to the BHEC combined cycle CTG/HRSGs.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 63 - National Emission Standards for Hazardous Air Pollutants for Source Categories: Subparts A, B, C, D, E, F, G, H, I, L, M, N, O, Q, R, S, T, U, W, X, Y, AA, BB, CC, DD, EE, GG, HH, II, JJ, KK, LL, OO, PP, QQ, RR, SS, TT, UU, VV, WW, YY, CCC, DDD, EEE, GGG, HHH, III, JJJ, LLL, MMM, NNN, OOO, PPP, RRR, TTT, VVV, and XXX		X		None of the listed NESHAPS' contain requirements which are applicable to the BHEC combined cycle CTG/HRSGs.
40 CFR Part 72 - Acid Rain Program Permits				
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CTG/HRSG Units 1-4	General Acid Rain Program requirements. SO_2 allowance program requirements start January 1, 2000 **(future requirement)**.
Subpart B - Designated Representative				
Designated Representative	§72.20 - §72.24		CTG/HRSG Units 1-4	General requirements pertaining to the Designated Representative.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CTG/HRSG Units 1-4	Requirement to submit a complete Phase II Acid Rain permit application to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation. **(future requirement)**. Requirement to submit a complete Acid Rain permit application for each source with an affected unit at least 6 months prior to the expiration of an existing Acid Rain permit governing the unit during Phase II or such longer time as may be approved under part 70 of this chapter that ensures that the term of the existing permit will not expire before the effective date of the permit for which the application is submitted. **(future requirement)**.
Permit Application Shield	§72.32		CTG/HRSG Units 1-4	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CTG/HRSG Units 1-4	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the BHEC combined cycle CTG/HRSGs.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CTG/HRSG Units 1-4	Units operating in compliance with an Acid Rain Permit are deemed to be operating in compliance with the Acid Rain Program.
Subpart H - Permit Revisions				
Fast-Track Modifications	§72.82(a) and (c)		CTG/HRSG Units 1-4	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CTG/HRSG Units 1-4	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CTG/HRSG Units 1-4	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CTG/HRSG Units 1-4	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CTG/HRSG Units 1-4	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CTG/HRSG Units 1-4	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CTG/HRSG Units 1-4	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CTG/HRSG Units 1-4	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CTG/HRSG Units 1-4	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CTG/HRSG Units 1-4	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CTG/HRSG Units 1-4	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CTG/HRSG Units 1-4	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CTG/HRSG Units 1-4	Specifies out-of-control periods and required actions to be taken when out-of-control periods occur (excluding opacity).
Subpart D - Missing Data Substitution Procedures				
General Provisions	§75.30(a)(3), (b), (c)		CTG/HRSG Units 1-4	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CTG/HRSG Units 1-4	Monitor data availability procedure requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Standard Missing Data Procedures	§75.33(a) and (c)		CTG/HRSG Units 1-4	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CTG/HRSG Units 1-4	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CTG/HRSG Units 1-4	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CTG/HRSG Units 1-4	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CTG/HRSG Units 1-4	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CTG/HRSG Units 1-4	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CTG/HRSG Units 1-4	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CTG/HRSG Units 1-4	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CTG/HRSG Units 1-4	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CTG/HRSG Units 1-4	Requires submittal of a recertification application within 30 days after completing the recertification test. **(potential future requirement)**
Quarterly Reports	§75.64(a)(1) - (5), (b), (c), and (d)		CTG/HRSG Units 1-4	Quarterly data report requirements.
40 CFR Part 76 - Acid Rain Nitrogen Oxides Emission Reduction Program		X		The Acid Rain Nitrogen Oxides Emission Reduction Program only applies to coal-fired utility units that are subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II.
40 CFR Part 77 - Excess Emissions				
Offset Plans for Excess Emissions of Sulfur Dioxide	§77.3		CTG/HRSG Units 1-4	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CTG/HRSG Units 1-4	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CTG/HRSG Units 1-4	Requirement to pay a penalty if excess emissions of SO_2 occur at any affected unit during any year (**potential future requirement**).
40 CFR Part 82 - Protection of Stratospheric Ozone				
Production and Consumption Controls	Subpart A	X		The BHEC combined cycle CTG/HRSGs will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		BHEC personnel will not perform servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner. All such servicing will be conducted by persons who comply with Subpart B requirements.
Ban on Nonessential Products Containing Class I Substances and Ban on Nonessential Products Containing or Manufactured with Class II Substances	Subpart C	X		BHEC will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		The BHEC combined cycle CTG/HRSGs will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		BHEC personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 10 of 11)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		BHEC personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		BHEC personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since CTG/HRSGs 1-4 will meet Acid Rain Program monitoring requirements.
40 CFR Part 68 - Provisions for Chemical Accident Prevention			Ammonia Storage	Subject to provisions of 40 CFR Part 68 due to ammonia storage.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 49, 53, 54, 55, 56, 57, 58, 59, 62, 66, 67, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 94, 95, 96, 97, 600, and 610		X		The listed regulations do not contain any requirements which are applicable to the BHEC combined cycle CTG/HRSGs.

Source: ECT, 2000.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 1 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-4, F.A.C. - Permits: Part I General					
Scope of Part I	62-4.001, F.A.C.	X			Contains no applicable requirements.
Definitions	62-4.020, .021, F.A.C.	X			Contains no applicable requirements.
Transferability of Definitions	62-4.021, .021, F.A.C.	X			Contains no applicable requirements.
General Prohibition	62-4.030, F.A.C		X		All stationary air pollution sources must be permitted, unless otherwise exempt-ed.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not re-quired.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to the BHEC combined cycle CTG/HRSGs.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial contruction permit. Modification of permit condi-tions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.-430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revo-cation criteria.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Financial Responsibility	62-4.110, F.A.C.	X			Contains no applicable requirements.
Transfer of Permits	62-4.120, F.A.C.	X			A sale or legal transfer of a permitted facility is not included in this application.
Plant Operation - Problems	62-4.130, F.A.C.		X		Immediate notification is required whenever the permittee is temporarily unable to comply with any permit condition. Notification content is specified. **(potential future requirement)**
Review	62-4.150, F.A.C.	X			Contains no applicable requirements.
Permit Conditions	62-4.160, F.A.C.	X			Contains no applicable requirements.
Scope of Part II	62-4.2.00, F.A.C.	X			Contains no applicable requirements.
Construction Permits	62-4.210, F.A.C.	X			General requirements for construction permits.
Operation Permits for New Sources	62-4.220, F.A.C.	X			General requirements for initial new source operation permits. **(future requirement)**
Water Permit Provisions	62-4.240 - 250, F.A.C.	X			Contains no applicable requirements.
Chapter 62-17, F.A.C. - Electrical Power Plant Siting		X			Power Plant Siting Act provisions.
Chapter 62-102, F.A.C. - Rules of Administrative Procedure - Rule Making			X		General administrative procedures.
Chapter 62-103, F.A.C. - Rules of Administrative Procedure - Final Agency Action			X		General administrative procedures.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 3 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-204, F.A.C. - State Implementation Plan					
State Implementation Plan	62-204.100, .200, .220(1)-(3), .240, .260, .320, .340, .360, .400, and .500, F.A.C.	X			Contains no applicable requirements.
Ambient Air Quality Protection	62-204.220(4), F.A.C.		X		Assessments of ambient air pollutant impacts must be made using applicable air quality models, data bases, and other requirements approved by FDEP and specified in 40 CFR Part 51, Appendix W.
State Implementation Plan	62-204.800(1) - (6), F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800(7)(a), (b)16.,(b)39., (c), (d), and (e), F.A.C.			CTG/HRSG Units 1-4	NSPS Subpart GG; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(8) - (13), (15), (17), (20), and (22) F.A.C.	X			Referenced federal regulations contain no applicable requirements.
State Implementation Plan	62-204.800 (14), (16), (18), (19), F.A.C.			CTG/HRSG Units 1-4	Acid Rain Program; see Table A-1 for detailed federal regulatory citations.
State Implementation Plan	62-204.800(21), F.A.C.		X		Protection of Stratospheric Ozone; see Table A-1 for detailed federal regulatory citations.
Chapter 62-210, F.A.C. - Stationary Sources - General Requirements					
Purpose and Scope	62-210.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-210.200, F.A.C.	X			Contains no applicable requirements.
Small Business Assistance Program	62-210.220, F.A.C.	X			Contains no applicable requirements.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 4 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permits Required	62-210.300(1) and (3), F.A.C.		X		Air construction permit required. Exemptions from permitting specified for certain facilities and sources.
Permits Required	62-210.300(2), F.A.C.		X		Air operation permit required. **(future requirement)**
Air General Permits	62-210.300(4), F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Notification of Startup	62-210.300(5), F.A.C.	X			Sources which have been shut down for more than one year shall notify the FDEP prior to startup.
Emission Unit Reclassification	62-210.300(6), F.A.C.		X		Emission unit reclassification **(potential future requirement)**
Public Notice and Comment					
Public Notice of Proposed Agency Action	62-210.350(1), F.A.C.		X		All permit applicants required to publish notice of proposed agency action.
Additional Notice Requirements for Sources Subject to Prevention of Significant Deterioration or Nonattainment Area New Source Review	62-210.350(2), F.A.C.		X		Additional public notice requirements for PSD and nonattainment area NSR applications.
Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources	62-210.350(3), F.A.C.		X		Notice requirements for Title V operating permit applicants **(future requirement)**.
Public Notice Requirements for FESOPS and 112(g) Emission Sources	62-210.350(4) and (5), F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Administrative Permit Corrections	62-210.360, F.A.C.	X			An administrative permit correction is not requested in this application.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 5 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reports Notification of Intent to Relocate Air Pollutant Emitting Facility	62-210.370(1), F.A.C.	X			Project does not have any relocatable emission units.
Annual Operating Report for Air Pollutant Emitting Facility	62-210.370(3), F.A.C.		X		Specifies annual reporting requirements. ***(future requirement)***.
Stack Height Policy	62-210.550, F.A.C.		X		Limits credit in air dispersion studies to good engineering practice (GEP) stack heights for stacks constructed or modified since 12/31/70.
Circumvention	62-210.650, F.A.C.		X		An applicable air pollution control device cannot be circumvented and must be operated whenever the emission unit is operating.
Excess Emissions	62-210.700(1), F.A.C.		X		Excess emissions due to startup, shut down, and malfunction are permitted for no more than two hours in any 24 hour period unless specifically authorized by the FDEP for a longer duration. **Excess emissions for up to 4 hours in a 24 hour period are specifically requested for the BHEC combined cycle CTG/HRSGs. See Section 2.2 of the PSD permit application for details.**
Excess Emissions	62-210.700(2) and (3), F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 6 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Excess Emissions	62-210.700(4), F.A.C.		X		Excess emissions caused entirely or in part by poor maintenance, poor operations, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction are prohibited. **(potential future requirement)**.
Excess Emissions	62-210.700(5), F.A.C.	X			Contains no applicable requirements.
Excess Emissions	62-210.700(6), F.A.C.		X		Excess emissions resulting from malfunctions must be reported to the FDEP in accordance with 62-4.130, F.A.C. **(potential future requirement)**.
Forms and Instructions	62-210.900, F.A.C.		X		Contains AOR requirements.
Notification Forms for Air General Permits	62-210.920, F.A.C.	X			Contains no applicable requirements.
Chapter 62-212, F.A.C. - Stationary Sources - Preconstruction Review					
Purpose and Scope	62-212.100, F.A.C.	X			Contains no applicable requirements.
General Preconstruction Review Requirements	62-212.300, F.A.C.		X		General air construction permit requirements.
Prevention of Significant Deterioration	62-212.400, F.A.C.		X		PSD permit required prior to construction of Project.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 7 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Chapter 62-213, F.A.C. - Operation Permits for Major Sources of Air Pollution					
Purpose and Scope	62-213.100, F.A.C.	X			Contains no applicable requirements.
Annual Emissions Fee	62-213.205(1), (4), and (5), F.A.C.		X		Annual emissions fee and documentation requirements. **(future requirement)**
Annual Emissions Fee	62-213.205(2) and (3), F.A.C.	X			Contains no applicable requirements.
Title V Air General Permits	62-213.300, F.A.C.	X			No eligible facilities
Permits and Permit Revisions Required	62-213.400, F.A.C.		X		Title V operation permit required. **(future requirement)**
Changes Without Permit Revision	62-213.410, F.A.C.		X		Certain changes may be made if specific notice and recordkeeping requirements are met **(potential future requirement)**.
Immediate Implementation Pending Revision Process	62-213.412, F.A.C.		X		Certain modifications can be implemented pending permit revision if specific criteria are met **(potential future requirement)**.
Fast-Track Revisions of Acid Rain Parts	62-213.413, F.A.C.			CTG/HRSG Units 1-4	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 8 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 9 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Applications	§62-214.320, F.A.C.			CTG/HRSG Units 1-4	Acid Rain application requirements. Application for new units are due at least 24 months before the later of 1/1/2000 or the date on which the unit commences operation. **(future requirement)**
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CTG/HRSG Units 1-4	Acid Rain compliance plan requirements. Sulfur dioxide requirements become effective the later of 1/1/2000 or the deadline for CEMS certification pursuant to 40 CFR Part 75. **(future requirement)**
Exemptions	§62-214.340, F.A.C.		X		An application may be submitted for certain exemptions **(potential future requirement)**.
Certification	§62-214.350, F.A.C.			CTG/HRSG Units 1-4	The designated representative must certify all Acid Rain submissions. **(future requirement)**
Department Action on Applications	§62-214.360, F.A.C.	X			Contains no applicable requirements.
Revisions and Administrative Corrections	§62-214.370, F.A.C.			CTG/HRSG Units 1-4	Defines revision procedures and automatic amendments **(potential future requirement)**..
Acid Rain Part Content	§62-214.420, F.A.C.	X			Agency procedures, contains no applicable requirements.
Implementation and Termination of Compliance Options	§62-214.430, F.A.C.			CTG/HRSG Units 1-4	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the BHEC combined cycle CTs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 10 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Chapter 62-256 - Open Burning and Frost Protection Fires					
Declaration and Intent	62-256.100, F.A.C.	X			Contains no applicable requirements.
Definitions	62-256.200, F.A.C.	X			Contains no applicable requirements.
Prohibitions	**62-256.300, F.A.C.**[1]		X		Prohibits open burning.
Burning for Cold and Frost Protection	62-256.450, F.A.C.	X			Limited to agricultural protection.
Land Clearing	**62-256.500, F.A.C.**[1]		X		Defines allowed open burning for non-rural land clearing and structure demolition.
Industrial, Commercial, Municipal, and Research Open Burning	**62-256.600, F.A.C.**[1]		X		Prohibits industrial open burning
Open Burning allowed	62-256.700, F.A.C.		X		Specifies allowable open burning activities. **(potential future requirement)**
Effective Date	62-256.800, F.A.C.	X			Contains no applicable requirements.
Chapter 62-257 - Asbestos Fee	62-257, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.

Table A-2. Summary of FDEP Regulatory Applicability and Corresponding Requirements (Page 11 of 12)

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Chapter 62-296 - Stationary Source - Emission Standards					
Purpose and Scope	62-296.100, F.A.C.	X			Contains no applicable requirements
General Pollutant Emission Limiting Standard, Volatile Organic Compounds Emissions	62-296.320(1), F.A.C.		X		Known and existing vapor control devices must be applied as required by the Department.
General Pollutant Emission Limiting Standard, Objectionable Odor Prohibited	62-296.320(2), F.A.C.		X		Objectionable odor release is prohibited.
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.[1]**		X		Open burning in connection with industrial, commercial, or municipal operations is prohibited.
General Particulate Emission Limiting Standard, Process Weight Table	62-296.320(4)(a), F.A.C.	X			Project does not have any applicable emission units. Combustion emission units are exempt per 62-296.320(4)(a)1a.
General Particulate Emission Limiting Standard, General Visible Emission Standard	62-296.320(4)(b), F.A.C.		X		Opacity limited to 20 percent, unless otherwise permitted. Test methods specified.
General Particulate Emission Limiting Standard, Unconfined Emission of Particulate Matter	62-296.320(4)(c), F.A.C.		X		Reasonable precautions must be taken to prevent unconfined particulate matter emission.
Specific Emission Limiting and Performance Standards	62-296.401 through 62-296.417, F.A.C.	X			None of the referenced standards are applicable to the BHEC combined cycle CTG/HRSGs.
Reasonably Available Control Technology (RACT) Volatile Organic Compounds (VOC) and Nitrogen Oxides (NO_x) Emitting Facilities	62-296.500 through 62-296.516, F.A.C.	X			Project is not located in an ozone nonattainment area or an ozone air quality maintenance area.

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

Regulation	Citation	Not Applicable	Applicable: Facility-Wide	Applicable: Emission Units	Applicable Requirement or Non-Applicability Rationale
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Project is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Project is not located in a lead nonattainment area or a lead air quality maintenance area.
Reasonably Available Control Technology (RACT)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Project is not located in a PM nonattainment area or a PM air quality maintenance area.
Chapter 62-297 - Stationary Sources - Emissions Monitoring					
Purpose and Scope	62-297.100, F.A.C.	X			Contains no applicable requirements.
General Compliance Test Requirements	62-297.310, F.A.C.		X		Specifies general compliance test requirements.
Compliance Test Methods	62-297.401, F.A.C.	X			Contains no applicable requirements.
Supplementary Test Procedures	62-297.440, F.A.C.	X			Contains no applicable requirements.
EPA VOC Capture Efficiency Test Procedures	62-297.450, F.A.C.	X			Not applicable to the BHEC combined cycle CTG/HRSGs.
CEMS Performance Specifications	62-297.520, F.A.C.	X			Contains no applicable requirements.
Exceptions and Approval of Alternate Procedures and Requirements	62-297.620, F.A.C.	X			Exceptions or alternate procedures have not been requested.

[1] - State requirement only; not federally enforceable.

Source: ECT, 2000.

ATTACHMENT A-2

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from BHEC operations include:

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

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

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

ATTACHMENT A-3

FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
Gas Composition	
Hexane+	0.018
Propane	0.190
I-butane	0.010
N-butane	0.007
Pentane	0.002
Nitrogen	0.527
Methane	96.195
CO_2	0.673
Ethane	2.379
Other Characteristics	
Heat content (HHV)	1,056 Btu/ft^3 with 14.73 psia, dry
Real specific gravity	0.5925
Sulfur content (maximum)	1.5 gr/100 scf

Note: Btu/ft^3 = British thermal units per cubic foot.
psia = pounds per square inch absolute.
gr/100 scf = grains per 100 standard cubic foot.

Source: ECT, 2000.

ATTACHMENT B

CTG VENDOR DATA

Calpine - Blue Heron

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
AEROPAC 2-95x200 / 0.90 Power Factor

SITE CONDITIONS:	**CASE 1**	**CASE 2**	**CASE 3**	**CASE 4**	**CASE 5**	**CASE 6**	**CASE 7**	**CASE 8**	**CASE 9**
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	PWR AUG	PWR AUG	BASE	BASE	70%	60%	BASE	BASE	70%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20,981	20,981	20,981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299	23,299	23,299
INLET FOGGING STATUS	ON	OFF	ON	OFF	OFF	OFF	ON	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	95.0	95.0	95.0	95.0	95.0	95.0	72.0	72.0	72.0
AMBIENT WET BULB TEMPERATURE, °F	89.3	89.3	89.3	89.3	89.3	89.3	67.6	67.6	67.6
AMBIENT RELATIVE HUMIDITY, %	80%	80%	80%	80%	80%	80%	80%	80%	80%
BAROMETRIC PRESSURE, psia	14.683	14.683	14.7	14.683	14.683	14.683	14.683	14.683	14.683
COMPRESSOR INLET TEMPERATURE, °F	91.3	95.0	91.3	95.0	95.0	95.0	69.6	72.0	72.0
INLET PRESSURE LOSS, inches of water (Total)	3.4	3.3	3.4	3.3	2.5	2.0	3.7	3.6	2.6
EXHAUST PRESSURE LOSS, inches of water (Total)	16.7	16.5	15.6	15.4	11.2	9.0	17.5	17.3	12.0
EXHAUST PRESSURE LOSS, inches of water (Static)	14.0	13.7	13.1	12.9	9.4	7.5	14.7	14.5	10.0
INJECTION FLUID	Steam	Steam	-	-	-	-	-	-	-
INJECTION RATIO	1.40	1.40	-	-	-	-	-	-	-
	PWR AUG	PWR AUG							
COMBUSTION TURBINE PERFORMANCE:									
GROSS POWER OUTPUT, kW	179,080	176,530	162,360	159,940	111,540	95,390	175,430	173,900	121,340
GROSS HEAT RATE, Btu/kWh (LHV)	9,200	9,225	9,525	9,555	10,495	11,025	9,320	9,335	10,120
GROSS HEAT RATE, Btu/kWh (HHV)	10,210	10,240	10,575	10,610	11,650	12,240	10,345	10,365	11,235
FUEL FLOW, lbm/hr	78,490	77,580	73,680	72,830	55,780	50,160	77,910	77,350	58,500
INJECTION RATE, lbm/hr	109,890	108,620	-	-	-	-	-	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,647	1,628	1,546	1,528	1,170	1,052	1,635	1,623	1,227
HEAT INPUT, mmBtu/hr (HHV)	1,829	1,808	1,717	1,697	1,300	1,169	1,815	1,802	1,363
EXHAUST TEMPERATURE, °F	1,134	1,136	1,136	1,138	1,070	1,093	1,114	1,115	1,054
EXHAUST FLOW, lbm/hr	3,423,539	3,394,530	3,311,993	3,284,380	2,848,186	2,544,620	3,523,128	3,505,134	2,965,059
EXHAUST GAS COMPOSITION (BY % VOL):									
OXYGEN	10.76	10.81	11.82	11.87	12.76	12.77	12.28	12.31	13.11
CARBON DIOXIDE	3.77	3.76	3.73	3.72	3.31	3.31	3.74	3.73	3.37
WATER	16.54	16.39	11.86	11.72	10.92	10.92	9.59	9.49	8.77
NITROGEN	68.07	68.18	71.69	71.80	72.10	72.10	73.47	73.54	73.82
ARGON	0.85	0.86	0.90	0.90	0.90	0.90	0.92	0.92	0.93
MOLECULAR WEIGHT	27.49	27.51	28.00	28.02	28.07	28.07	28.25	28.26	28.31
NET EMISSIONS: Based on Westinghouse 21T5620 test methods									
NOx, ppmvd @ 15% O2	25	25	25	25	25	25	25	25	25
NOx, lbm/hr as NO2	171	169	161	159	122	109	170	169	128
CO, ppmvd @ 15% O2	25	25	10	10	10	50	10	10	10
CO, lbm/hr	105	103	39	39	30	133	42	41	32
SO2, lbm/hr	1.1	1.1	1.1	1.0	0.8	0.7	1.1	1.1	0.8
VOC, ppmvd @ 15% O2 as CH4	1.2	1.2	1.2	1.2	2.3	3.0	1.2	1.2	2.3
VOC, lbm/hr as CH4	2.9	2.8	2.7	2.7	3.9	4.6	2.8	2.8	4.1
PARTICULATES, lbm/hr	14.1	14.0	14.1	14.0	12.2	10.9	15.3	15.2	12.9
WASTE HEAT FROM ROTOR COOLING AIR, mmBtu/hr	22.49	22.59	21.14	21.24	15.38	12.33	20.94	21.02	14.58

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus excitation losses.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- Actual exhaust flow can deviate from the calculated numbers.
- Emission flowrates are calculated based on the maximum achievable exhaust flow. For further details on flowrate calculation contact SWPC.
- VOC's are non methane, non ethane.
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the latest revision of the Siemens Westinghouse Gas Fuel Spec (21T0306).
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 201A/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Average temperature of the gas fuel is 280 °F. Sensible heat of the fuel is not included in the fuel heating values, heat input, or heat rate.
- Injection is for power augmentation and not for NO_x control.
- Actual IGV schedule may vary. Part load performance will be adjusted accordingly.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.
- Maximum gross power is 214.8 MW.
- Inlet fogging calculations were performed based on maintaining the compressor inlet temperature a minimum of 2F higher than the ambient wet bulb temperature.

SIEMENS Westinghouse

Calpine - Blue Heron

Expected 501F Combustion Turbine Performance
Combined Cycle / Dry Low NOx Combustor
AEROPAC 2-95x200 / 0.90 Power Factor

SITE CONDITIONS:	CASE 10	CASE 11	CASE 12	CASE 13	CASE 14	CASE 15	CASE 16	CASE 17	CASE 18
FUEL TYPE	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
LOAD LEVEL	60%	BASE	70%	60%	PWR AUG	BASE	PWR AUG	BASE	70%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981	20,981	20,981	20,981	20,981	20,981	20,981	20,981	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299	23,299	23,299	23,299	23,299	23,299	23,299	23,299	23,299
INLET FOGGING STATUS	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF	OFF
AMBIENT DRY BULB TEMPERATURE, °F	72.0	59.0	59.0	59.0	32.0	32.0	20.0	20.0	20.0
AMBIENT WET BULB TEMPERATURE, °F	67.6	51.5	51.5	51.5	27.8	27.8	17.1	17.1	17.1
AMBIENT RELATIVE HUMIDITY, %	80%	60%	60%	60%	60%	60%	60%	60%	60%
BAROMETRIC PRESSURE, psia	14.683	14.683	14.683	14.683	14.683	14.683	14.683	14.683	14.683
COMPRESSOR INLET TEMPERATURE, °F	72.0	59.0	59.0	59.0	32.0	32.0	20.0	20.0	20.0
INLET PRESSURE LOSS, inches of water (Total)	2.1	3.8	2.7	2.1	4.0	4.0	4.0	4.0	2.7
EXHAUST PRESSURE LOSS, inches of water (Total)	9.9	18.4	12.4	10.3	21.6	20.2	21.6	20.7	13.7
EXHAUST PRESSURE LOSS, inches of water (Static)	8.3	15.5	10.4	8.6	18.1	17.0	18.1	17.4	11.5
INJECTION FLUID	-	-	-	-	Steam	-	Steam	-	-
INJECTION RATIO	-	-	-	-	1.40	-	1.10	-	-
					PWR AUG		PWR AUG		
COMBUSTION TURBINE PERFORMANCE:									
GROSS POWER OUTPUT, kW	103,790	181,430	126,620	108,320	213,990	195,280	214,800	200,660	140,130
GROSS HEAT RATE, Btu/kWh (LHV)	10,805	9,240	9,970	10,685	8,870	9,115	8,880	9,075	9,680
GROSS HEAT RATE, Btu/kWh (HHV)	11,995	10,260	11,065	11,860	9,845	10,120	9,860	10,070	10,745
FUEL FLOW, lbm/hr	53,490	79,900	60,150	55,200	90,530	84,830	90,980	86,750	64,630
INJECTION RATE, lbm/hr	-	-	-	-	126,740	-	99,990	-	-
HEAT INPUT, mmBtu/hr (LHV)	1,122	1,676	1,262	1,158	1,899	1,780	1,909	1,820	1,356
HEAT INPUT, mmBtu/hr (HHV)	1,246	1,862	1,401	1,286	2,109	1,977	2,120	2,021	1,506
EXHAUST TEMPERATURE, °F	1,106	1,104	1,048	1,108	1,093	1,089	1,084	1,085	1,024
EXHAUST FLOW, lbm/hr	2,637,758	3,625,080	3,027,725	2,688,942	3,935,599	3,806,001	3,968,111	3,866,117	3,192,417
EXHAUST GAS COMPOSITION (BY % VOL):									
OXYGEN	12.97	12.51	13.25	13.07	11.41	12.53	11.65	12.50	13.25
CARBON DIOXIDE	3.43	3.74	3.41	3.49	3.84	3.79	3.84	3.82	3.48
WATER	8.90	8.44	7.77	7.94	12.88	7.91	11.71	7.83	7.16
NITROGEN	73.77	74.37	74.63	74.56	70.98	74.82	71.89	74.91	75.17
ARGON	0.93	0.93	0.94	0.94	0.89	0.94	0.90	0.94	0.94
MOLECULAR WEIGHT	28.30	28.38	28.42	28.41	27.90	28.44	28.03	28.45	28.49
NET EMISSIONS: Based on Westinghouse 21T5620 test methods									
NOx, ppmvd @ 15% O2	25	25	25	25	25	25	25	25	25
NOx, lbm/hr as NO2	116	174	132	120	197	185	198	189	142
CO, ppmvd @ 15% O2	50	10	10	50	25	10	25	10	10
CO, lbm/hr	142	43	32	147	120	45	121	46	35
SO2, lbm/hr	0.8	1.1	0.9	0.8	1.3	1.2	1.3	1.2	0.9
VOC, ppmvd @ 15% O2 as CH4	3.0	1.2	2.3	3.0	1.2	1.2	1.2	1.2	2.3
VOC, lbm/hr as CH4	4.9	2.9	4.2	5.0	3.3	3.1	3.3	3.2	4.5
PARTICULATES, lbm/hr	11.5	15.8	13.3	11.8	16.6	16.7	16.9	16.9	14.1
WASTE HEAT FROM ROTOR COOLING AIR, mmBtu/hr	11.72	20.79	14.10	11.33	20.89	19.50	19.69	18.66	12.27

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus excitation losses.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- Actual exhaust flow can deviate from the calculated numbers.
- Emission flowrates are calculated based on the maximum achievable exhaust flow. For further details on flowrate calculation contact SWPC.
- VOC's are non methane, non ethane.
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the latest revision of the Siemens Westinghouse Gas Fuel Spec (21T0306).
- Liquid condensable fuels must be removed from the fuel lines.
- Particulates are per US EPA Method 201A/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Average temperature of the gas fuel is 280 °F. Sensible heat of the fuel is not included in the fuel heating values, heat input, or heat rate.
- Injection is for power augmentation and not for NO_x control.
- Actual IGV schedule may vary. Part load performance will be adjusted accordingly.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.
- Maximum gross power is 214.8 MW.
- Inlet fogging calculations were performed based on maintaining the compressor inlet temperature a minimum of 2F higher than the ambient wet bulb temperature.

SITE CONDITIONS:	CASE 19
FUEL TYPE	Natural Gas
LOAD LEVEL	60%
NET FUEL HEATING VALUE, Btu/lbm (LHV)	20,981
GROSS FUEL HEATING VALUE, Btu/lbm (HHV)	23,299
INLET FOGGING STATUS	OFF
AMBIENT DRY BULB TEMPERATURE, °F	20.0
AMBIENT WET BULB TEMPERATURE, °F	17.1
AMBIENT RELATIVE HUMIDITY, %	60%
BAROMETRIC PRESSURE, psia	14.683
COMPRESSOR INLET TEMPERATURE, °F	20.0
INLET PRESSURE LOSS, inches of water (Total)	2.1
EXHAUST PRESSURE LOSS, inches of water (Total)	11.1
EXHAUST PRESSURE LOSS, inches of water (Static)	9.3
INJECTION FLUID	-
INJECTION RATIO	-
COMBUSTION TURBINE PERFORMANCE:	
GROSS POWER OUTPUT, kW	119,910
GROSS HEAT RATE, Btu/kWh (LHV)	10,195
GROSS HEAT RATE, Btu/kWh (HHV)	11,315
FUEL FLOW, lbm/hr	58,310
INJECTION RATE, lbm/hr	-
HEAT INPUT, mmBtu/hr (LHV)	1,223
HEAT INPUT, mmBtu/hr (HHV)	1,358
EXHAUST TEMPERATURE, °F	1,063
EXHAUST FLOW, lbm/hr	2,822,770
EXHAUST GAS COMPOSITION (BY % VOL):	
OXYGEN	13.16
CARBON DIOXIDE	3.52
WATER	7.23
NITROGEN	75.14
ARGON	0.94
MOLECULAR WEIGHT	28.49
NET EMISSIONS: Based on Westinghouse 21T5620 test methods	
NOx, ppmvd @ 15% O2	25
NOx, lbm/hr as NO2	127
CO, ppmvd @ 15% O2	50
CO, lbm/hr	155
SO2, lbm/hr	0.8
VOC, ppmvd @ 15% O2 as CH4	3.0
VOC, lbm/hr as CH4	5.3
PARTICULATES, lbm/hr	12.4
WASTE HEAT FROM ROTOR COOLING AIR, mmBtu/hr	9.70

NOTES:

- Performance based on new and clean condition.
- All data is expected and not guaranteed.
- Gross power output is at the generator terminals minus excitation losses.
- Expected CT Performance values are dependent upon receiving test tolerances persuant to the latest revision of SWPC EC- 93208.
- Actual exhaust flow can deviate from the calculated numbers.
- Emission flowrates are calculated based on the maximum achievable exhaust flow. For further details on flowrate calculation contact SWPC.
- VOC's are non methane, non ethane.
- Gas fuel composition is 98% CH4, 0.6% C2H6, 1.4% N2, 0.2 grains of sulfur per 100 SCF.
- Gas fuel must be in compliance with the latest revision of the Siemens Westinghouse Gas Fuel Spec (21T0306).
- *Liquid condensable fuels must be removed from the fuel lines.*
- Particulates are per US EPA Method 201A/202 (front and back half).
- The information contained in this transmittal has been prepared and submitted per the customer's request. Data included in any permit application or Environmental Impact Statement are strictly the responsibility of the Owner. Westinghouse is available to review permit application data upon request.
- Dry Low NOx combustor utilizing a high ethane content gas fuel may produce a visible plume at the stack.
- Average temperature of the gas fuel is 280 °F. Sensible heat of the fuel is not included in the fuel heating values, heat input, or heat rate.
- Injection is for power augmentation and not for NO_x control.
- Actual IGV schedule may vary. Part load performance will be adjusted accordingly.
- Part load is achieved by modulating the IGVs and is based on percentage unrestricted power output.
- Maximum gross power is 214.8 MW.
- Inlet fogging calculations were performed based on maintaining the compressor inlet temperature a minimum of 2F higher than the ambient wet bulb temperature.

ATTACHMENT C

EMISSION RATE CALCULATIONS

Table [illegible] Calpine Blue Heron
CTG/HRSG Operating Scenarios

Case No.	Westinghouse Case No.	Ambient Temperature (°F)	Turbine Inlet Temperature (°F)	Load (%)	CTG 1-4	Annual Profile A (hr/yr)	Annual Profile B (hr/yr)	Annual Profile C (hr/yr)	Annual Profile D (hr/yr)	Evaporative Cooling	Steam Power Augmentation	Duct Burner Firing
		Winter										
1	17	20.0	20.0	100	X							
2		20.0	20.0	100	X							X
3	16	20.0	20.0	100	X						X	
4		20.0	20.0	100	X						X	X
5	18	20.0	20.0	70	X							
6	19	20.0	20.0	60	X							
		ISO										
7	11	59.0	59.0	100	X	8,760	5,880	5,700	4,380			
8	12	59.0	59.0	70	X							
9	13	59.0	59.0	60	X			1,500	1,500			
		Annual Average										
10	8	72.0	72.0	100	X							
11	7	72.0	69.6	100	X					X		
12		72.0	69.6	100	X					X		X
13	9	72.0	72.0	70	X							
14	10	72.0	72.0	60	X							
		Summer										
15	4	95.0	95.0	100	X							
16	2	95.0	95.0	100	X						X	
17	3	95.0	91.3	100	X					X		
18		95.0	91.3	100	X					X		X
19	1	95.0	91.3	100	X			1,560		X	X	
20		95.0	95.0	100	X		2,880		2,880	X	X	X
21	5	95.0	95.0	70	X							
22	6	95.0	95.0	60	X							

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-2. Calpine Blue Heron (Page 1 of 2)
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp. (°F)	Case	Load (%)	PM_{10}[1] (lb/hr)	PM_{10}[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead (lb/hr)	Lead (g/sec)
20	1	100	19.0	2.398	8.6	1.085	1.58	0.199	0.0322	0.00405
	2	100	25.8	3.249	9.8	1.233	1.80	0.227	0.0365	0.00460
	3	100	19.1	2.411	9.0	1.138	1.66	0.209	0.0337	0.00425
	4	100	**26.0**	**3.276**	**10.2**	**1.286**	**1.88**	**0.236**	**0.0381**	**0.00480**
	5	70	15.7	1.977	6.4	0.809	1.18	0.149	0.0240	0.00302
	6	60	13.8	1.743	5.8	0.729	1.06	0.134	0.0216	0.00272
59	7	100	17.8	2.238	7.9	1.000	1.46	0.184	0.0296	0.00373
	8	70	14.8	1.862	6.0	0.752	1.10	0.138	0.0223	0.00281
	9	60	13.2	1.658	5.5	0.690	1.01	0.127	0.0205	0.00258
72	10	100	17.1	2.155	7.7	0.967	1.41	0.178	0.0287	0.00361
	11	100	17.2	2.169	7.7	0.974	1.42	0.179	0.0289	0.00364
	12	100	23.8	2.993	8.9	1.122	1.64	0.206	0.0333	0.00419
	13	70	14.3	1.807	5.8	0.732	1.07	0.134	0.0217	0.00273
	14	60	12.8	1.615	5.3	0.669	0.98	0.123	0.0198	0.00250
95	15	100	15.8	1.990	7.2	0.911	1.33	0.167	0.0270	0.00340
	16	100	15.9	2.004	7.7	0.971	1.42	0.178	0.0288	0.00362
	17	100	15.9	2.005	7.3	0.922	1.34	0.169	0.0273	0.00344
	18	100	22.3	2.816	8.5	1.070	1.56	0.197	0.0317	0.00399
	19	100	16.0	2.020	7.8	0.982	1.43	0.180	0.0291	0.00367
	20	100	22.6	2.845	9.0	1.130	1.65	0.208	0.0335	0.00422
	21	70	13.6	1.710	5.5	0.698	1.02	0.128	0.0207	0.00261
	22	60	12.1	1.529	5.0	0.628	0.92	0.115	0.0186	0.00234
		Maximums	**26.0**	**3.276**	**10.2**	**1.286**	**1.88**	**0.236**	**0.0381**	**0.00480**

Table C-2. Calpine Blue Heron (Page 2 of 2)
CTG/HRSG Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp.	Case	Load	NO_x			CO			VOC		
(°F)		(%)	(ppmvd)[4]	(lb/hr)	(g/sec)	(ppmvd)[4]	(lb/hr)	(g/sec)	(ppmvd)[4]	(lb/hr)[5]	(g/sec)
20	1	100	3.5	26.5	3.334	10.0	46.0	5.796	1.2	3.2	0.403
	2	100	3.5	30.6	3.854	14.9	74.9	9.437	3.1	9.0	1.131
	3	100	3.5	27.7	3.493	25.0	121.0	15.246	1.2	3.3	0.416
	4	100	3.5	**31.9**	**4.014**	37.0	**193.3**	**24.350**	5.9	**17.8**	**2.237**
	5	70	3.5	19.9	2.505	10.0	35.0	4.410	2.3	4.5	0.567
	6	60	3.5	17.8	2.240	**50.0**	155.0	19.530	3.0	5.3	0.668
59	7	100	3.5	24.4	3.069	10.0	43.0	5.418	1.2	2.9	0.365
	8	70	3.5	18.5	2.328	10.0	32.0	4.032	2.3	4.2	0.529
	9	60	3.5	16.8	2.117	**50.0**	147.0	18.522	3.0	5.0	0.630
72	10	100	3.5	23.7	2.981	10.0	41.0	5.166	1.2	2.8	0.353
	11	100	3.5	23.8	2.999	10.0	42.0	5.292	1.2	2.8	0.353
	12	100	3.5	27.9	3.511	15.5	70.9	8.933	3.3	8.6	1.081
	13	70	3.5	17.9	2.258	10.0	32.0	4.032	2.3	4.1	0.517
	14	60	3.5	16.2	2.046	**50.0**	142.0	17.892	3.0	4.9	0.617
95	15	100	3.5	22.3	2.805	10.0	39.0	4.914	1.2	2.7	0.340
	16	100	3.5	23.7	2.981	25.0	103.0	12.978	1.2	2.8	0.353
	17	100	3.5	22.5	2.840	10.0	39.0	4.914	1.2	2.7	0.340
	18	100	3.5	26.6	3.350	15.6	67.9	8.555	3.4	8.5	1.068
	19	100	3.5	23.9	3.016	25.0	105.0	13.230	1.2	2.9	0.365
	20	100	3.5	28.1	3.537	38.5	177.3	22.334	**6.6**	17.4	2.186
	21	70	3.5	17.1	2.152	10.0	30.0	3.780	2.3	3.9	0.491
	22	60	3.5	15.3	1.923	**50.0**	133.0	16.758	3.0	4.6	0.580
		Maximums	**3.5**	**31.9**	**4.014**	**50.0**	**193.3**	**24.350**	**6.6**	**17.8**	**2.237**

1 As measured by EPA Reference Methods 201A/202. Includes 12% conversion of fuel S to SO_3 and 100% conversion of SO_3 to $(NH_4)_2SO_2$ due to SCR.
2 Based on natural gas sulfur content of 1.5 gr/100 ft^3.
3 Based on 8.0% conversion of fuel S to SO_3 (CTG), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
4 Corrected to 15% O_2.
5 Non-methane, non-ethane VOCs expressed as methane equivalents.

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-3.A. Calpine Blue Heron
Duct Burner Hourly Emission Rates - Without SCR and Without Power Augmentation (Per Duct Burner)

Load (%)	Heat Input (MMBtu/hr)	PM/PM_{10} [1]			SO_2 [2]			H_2SO_4 [3]		
		(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)
100	289	0.015	4.3	0.55	0.0041	1.2	0.15	0.00075	0.22	0.027
75	217	0.015	3.3	0.41	0.0041	0.9	0.11	0.00075	0.16	0.020
50	145	0.015	2.2	0.27	0.0041	0.6	0.07	0.00075	0.11	0.014
Maximum		**0.015**	**4.3**	**0.55**	**0.0041**	**1.2**	**0.15**	**0.00075**	**0.22**	**0.027**

Load (%)	Heat Input (MMBtu/hr)	NO_x			CO			VOC [4]		
		(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)
100	289	0.080	23.1	2.91	0.100	28.9	3.64	0.020	5.8	0.73
75	217	0.080	17.3	2.18	0.100	21.7	2.73	0.020	4.3	0.55
50	145	0.080	11.6	1.46	0.100	14.5	1.82	0.020	2.9	0.36
Maximum		**0.080**	**23.1**	**2.91**	**0.100**	**28.9**	**3.64**	**0.020**	**5.8**	**0.73**

[1] As measured by EPA Reference Methods 201A/202.
[2] Based on natural gas sulfur content of 1.5 gr/100 ft^3.
[3] Based on 8.0% conversion of fuel S to SO_3 (DB), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[4] Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2000.
Calpine, 2000.

Table C-3.B. Calpine Blue Heron
Duct Burner Hourly Emission Rates - Without SCR and With Power Augmentation (Per Duct Burner)

Load (%)	Heat Input (MMBtu/hr)	PM/PM_{10}[1]			SO_2[2]			H_2SO_4[3]		
		(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)
100	289	0.015	4.3	0.55	0.0041	1.2	0.15	0.00075	0.22	0.027
75	217	0.015	3.3	0.41	0.0041	0.9	0.11	0.00075	0.16	0.020
50	145	0.015	2.2	0.27	0.0041	0.6	0.07	0.00075	0.11	0.014
Maximum		**0.015**	**4.3**	**0.55**	**0.0041**	**1.2**	**0.15**	**0.00075**	**0.22**	**0.027**

Load (%)	Heat Input (MMBtu/hr)	NO_x			CO			VOC[4]		
		(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)	(lb/MMBtu)	(lb/hr)	(g/sec)
100	289	0.080	23.1	2.91	0.250	72.3	9.10	0.050	14.5	1.82
75	217	0.080	17.3	2.18	0.250	54.2	6.83	0.050	10.8	1.37
50	145	0.080	11.6	1.46	0.250	36.1	4.55	0.050	7.2	0.91
Maximum		**0.080**	**23.1**	**2.91**	**0.250**	**72.3**	**9.10**	**0.050**	**14.5**	**1.82**

[1] As measured by EPA Reference Methods 201A/202.
[2] Based on natural gas sulfur content of 1.5 gr/100 ft^3.
[3] Based on 8.0% conversion of fuel S to SO_3 (DB), 4.0% conversion of SO_2 to SO_3 (SCR), and 100% conversion of SO_3 to H_2SO_4.
[4] Non-methane, non-ethane hydrocarbons (NMHC) expressed as methane.

Sources: ECT, 2000.
Calpine, 2000.

NATURAL GAS-FIRED COMBUSTION TURBINES HAZARDOUS AIR POLLUTANT EMISSION FACTORS

Section 3.1 of AP-42, Stationary Gas Turbines, was revised in April 2000 to include natural gas-fired combustion turbine generator (CTG) emission factors for 11 hazardous air pollutants (HAPs), including formaldehyde and toluene. The April 2000 AP-42 formaldehyde and toluene emission factors for natural gas-fired CTGs are 7.1×10^{-4} and 1.3×10^{-4} lb/10^6 Btu, respectively.

As stated in the introduction to AP-42, the emission factors in AP-42 are "simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average)". Accordingly, the emission factors in AP-42 are generally appropriate for use in making areawide emission inventories. Because the AP-42 emission factors represent a source category population average, the factors do not necessarily reflect the emission rates for any particular member of that source category population.

In the case of the formaldehyde emission factor for natural gas-fired CTGs, the April 2000 AP-42 emission factor is based on the average of 22 CTG source tests. The CTGs in the 22 source test database include small CTGs (9 of the 22 CTGs tested, or 40 percent of all units tested, had a rating of less than 15 MW), aircraft-derivative CTGs (5 of the 22 CTGs, or 23 percent of all units tested, were GE LM series aircraft-derivative CTGs), and frame-type CTGs. The largest CTG of the 22 units tested was a GE Frame 7E unit with a rating of 87.8 MW. The average rating of the 22 CTGs tested is 30.2 MW. The majority of the CTGs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CTG test database shows considerable variability in formaldehyde emission factors. The maximum formaldehyde emission factor (5.61×10^{-3} lb/10^6 Btu) is 2,538 times higher than the minimum factor (2.21×10^{-6} lb/10^6 Btu). Six of the 22 test series include runs for which there were no detectable emissions of formaldehyde.

The CTGs proposed for the BHEC are natural gas-fired Siemens Westinghouse 501F units each rated at a nominal 170 MW. Dry low-NO_x (DLN) combustor and SCR control technology will be employed to control NO_x emissions. Accordingly, the average April 2000 AP-42 formaldehyde emission factor for natural gas-fired CTGs is not considered applicable to the Siemens Westinghouse 501F CTG. The Siemens Westinghouse 501F CTG is 5.9 times larger (i.e., has a rating of 180 vs. 30.6 MW) than the average CTG included in the AP-42 CTG database and is equipped with DLN and SCR control technology.

Evaluation of the AP-42 CTG formaldehyde source test database shows that six of the units tested were large, frame-type CTGs. Emission factors for these six CTGs were averaged to develop a formaldehyde emission factor which is considered to be more representative of the Siemens Westinghouse 501F units. This average factor for frame-type CTGs, 1.14 x 10^{-4} lb/10^6 Btu, was used to estimate emissions of formaldehyde for the BHEC CTGs.

A similar analysis was conducted with respect to the April 2000 AP-42 toluene emission factor for natural gas-fired CTGs. The April 2000 AP-42 toluene emission factor is based on the average of seven CTG source tests. The CTGs in the seven source test database include small CTGs (three of the seven CTGs tested, or 43 percent of all units tested, had a rating of less than 15 MW), aircraft-derivative CTGs (two of the seven CTGs, or 29 percent of all units tested, were GE LM series aircraft-derivative CTGs), and frame-type CTGs. The largest CTG of the seven units tested was a GE Frame 7 unit with a rating of 75 MW. The average rating of the seven CTGs tested is 26.6 MW. The majority of the CTGs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CTG test database also shows variability in toluene emission factors. The maximum toluene emission factor (7.10 x 10^{-4} lb/10^6 Btu) is 67.6 times higher than the minimum factor (1.05×10^{-5} lb/10^6 Btu). Two of the seven test series include runs for which there were no detectable emissions of toluene.

Evaluation of the AP-42 CTG toluene source test database shows that two of the units tested were large, frame-type CTGs. Emission factors for these two CTGs were averaged to develop a toluene emission factor which is considered to be more representative of the Siemens Westinghouse 501F units. This average factor for frame-type CTGs, 6.80×10^{-5} lb/10^6 Btu, was used to estimate emissions of toluene for the BHEC CTGs.

Analyses of the natural gas-fired CTG AP-42 emission factors for the remaining listed HAPs were conducted using the methodology described above for formaldehyde and toluene.

Table C.4.A. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile A

Parameter	Units	Annual Profile A		
		Case 7		
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,955	N/A	N/A
Maximum Annual Hours:	hrs/yr	8,760	N/A	N/A

Pollutant	Emission Factor [a], [b] (lb/10^6 Btu)	Emission Rates (Per CTG)				CTG 1-4 Annual (ton/yr)
		Case 7 (lb/hr)			Annual (ton/yr)	
1,3-Butadiene	6.05E-08	0.0001			0.0005	0.0021
Acetaldehyde	4.31E-05	0.084			0.3691	1.48
Acrolein	5.60E-06	0.011			0.0480	0.19
Arsenic	N/A	N/A			N/A	N/A
Benzene	1.83E-05	0.036			0.157	0.63
Beryllium	N/A	N/A			N/A	N/A
Cadmium	N/A	N/A			N/A	N/A
Chromium	N/A	N/A			N/A	N/A
Cobalt	N/A	N/A			N/A	N/A
Dichlorobenzene	N/A	N/A			N/A	N/A
Ethylbenzene	2.28E-05	0.045			0.195	0.78
Formaldehyde	1.14E-04	**0.223**			**0.976**	**3.90**
Hexane	N/A	N/A			N/A	N/A
Lead	N/A	N/A			N/A	N/A
Manganese	N/A	N/A			N/A	N/A
Mercury	7.80E-10	0.0000015			0.000007	0.000027
Naphthalene	6.33E-07	0.001			0.005	0.022
Nickel	N/A	N/A			N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001			0.004	0.016
Polycyclic Organic Matter	N/A	N/A			N/A	N/A
Propylene Oxide	2.86E-05	0.056			0.245	0.980
Selenium	N/A	N/A			N/A	N/A
Toluene	6.80E-05	0.133			0.582	2.329
Xylene	6.51E-05	0.127			0.557	2.230
Maximum Individual HAP		0.223			0.976	3.905
Total HAPs		0.717			3.140	12.560

[a] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
[b] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: ECT, 2000.
Siemens Westinghouse, 2000.
Calpine, 2000.

Table C.4.B. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile B

Parameter	Units	Annual Profile B		
		Case 7	Case 20	
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,955	1,920	N/A
Maximum Annual Hours:	hrs/yr	5,880	2,880	N/A

Pollutant	Emission Factor [a], [b] (lb/10^6 Btu)	Emission Rates (Per CTG)				CTG 1-4
		Case 7 (lb/hr)	Case 20 (lb/hr)		Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001		0.0005	0.002
Acetaldehyde	4.31E-05	0.084	0.083		0.3669	1.468
Acrolein	5.60E-06	0.011	0.011		0.0477	0.191
Arsenic	N/A	N/A	N/A		N/A	N/A
Benzene	1.83E-05	0.036	0.035		0.1558	0.623
Beryllium	N/A	N/A	N/A		N/A	N/A
Cadmium	N/A	N/A	N/A		N/A	N/A
Chromium	N/A	N/A	N/A		N/A	N/A
Cobalt	N/A	N/A	N/A		N/A	N/A
Dichlorobenzene	N/A	N/A	N/A		N/A	N/A
Ethylbenzene	2.28E-05	0.045	0.044		0.1941	0.776
Formaldehyde	1.14E-04	**0.223**	**0.219**		**0.9705**	**3.882**
Hexane	N/A	N/A	N/A		N/A	N/A
Lead	N/A	N/A	N/A		N/A	N/A
Manganese	N/A	N/A	N/A		N/A	N/A
Mercury	7.80E-10	0.0000015	0.0000015		0.0000066	0.000027
Naphthalene	6.33E-07	0.001	0.001		0.0054	0.022
Nickel	N/A	N/A	N/A		N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001		0.0040	0.016
Polycyclic Organic Matter	N/A	N/A	N/A		N/A	N/A
Propylene Oxide	2.86E-05	0.056	0.055		0.2435	0.974
Selenium	N/A	N/A	N/A		N/A	N/A
Toluene	6.80E-05	0.133	0.131		0.5789	2.316
Xylene	6.51E-05	0.127	0.125		0.5542	2.217
Maximum Individual HAP		0.223	0.219		0.971	3.882
Total HAPs		0.717	0.704		3.122	12.486

[a] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
[b] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: ECT, 2000.
Siemens Westinghouse, 2000.
Calpine, 2000.

Table C.4.C. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile C

Parameter	Units	Annual Profile C		
		Case 7	Case 9	Case 19
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,955	1,350	1,920
Maximum Annual Hours:	hrs/yr	5,700	1,500	1,560

Pollutant	Emission Factor [(a),(b)] ($lb/10^6$ Btu)	Emission Rates (Per CTG)				CTG 1-4
		Case 7 (lb/hr)	Case 9 (lb/hr)	Case 19 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.084	0.058	0.083	0.3484	1.393
Acrolein	5.60E-06	0.011	0.008	0.011	0.0453	0.181
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.036	0.025	0.035	0.1479	0.592
Beryllium	N/A	N/A	N/A	N/A	N/A	N/A
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Dichlorobenzene	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.045	0.031	0.044	0.1843	0.737
Formaldehyde	1.14E-04	**0.223**	**0.154**	**0.219**	**0.9214**	**3.686**
Hexane	N/A	N/A	N/A	N/A	N/A	N/A
Lead	N/A	N/A	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000015	0.0000011	0.0000015	0.0000063	0.000025
Naphthalene	6.33E-07	0.001	0.001	0.001	0.0051	0.020
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.0038	0.015
Polycyclic Organic Matter	N/A	N/A	N/A	N/A	N/A	N/A
Propylene Oxide	2.86E-05	0.056	0.039	0.055	0.2312	0.925
Selenium	N/A	N/A	N/A	N/A	N/A	N/A
Toluene	6.80E-05	0.133	0.092	0.131	0.5496	2.198
Xylene	6.51E-05	0.127	0.088	0.125	0.5262	2.105
Maximum Individual HAP		0.223	0.154	0.219	0.921	3.686
Total HAPs		0.717	0.495	0.704	2.964	11.855

[(a)] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
[(b)] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: ECT, 2000.
Siemens Westinghouse, 2000.
Calpine, *2000*.

Table C.4.D. Calpine Blue Heron
CTG: Hazardous Air Pollutants - Annual Profile D

Parameter	Units	Annual Profile D		
		Case 7	Case 9	Case 20
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,955	1,350	1,920
Maximum Annual Hours:	hrs/yr	4,380	1,500	2,880

Pollutant	Emission Factor [(a), (b)] (lb/10^6 Btu)	Emission Rates (Per CTG)				CTG 1-4
		Case 7 (lb/hr)	Case 9 (lb/hr)	Case 20 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0005	0.002
Acetaldehyde	4.31E-05	0.084	0.058	0.083	0.3474	1.390
Acrolein	5.60E-06	0.011	0.008	0.011	0.0451	0.181
Arsenic	N/A	N/A	N/A	N/A	N/A	N/A
Benzene	1.83E-05	0.036	0.025	0.035	0.1475	0.590
Beryllium	N/A	N/A	N/A	N/A	N/A	N/A
Cadmium	N/A	N/A	N/A	N/A	N/A	N/A
Chromium	N/A	N/A	N/A	N/A	N/A	N/A
Cobalt	N/A	N/A	N/A	N/A	N/A	N/A
Dichlorobenzene	N/A	N/A	N/A	N/A	N/A	N/A
Ethylbenzene	2.28E-05	0.045	0.031	0.044	0.1838	0.735
Formaldehyde	1.14E-04	**0.223**	**0.154**	**0.219**	**0.9188**	**3.675**
Hexane	N/A	N/A	N/A	N/A	N/A	N/A
Lead	N/A	N/A	N/A	N/A	N/A	N/A
Manganese	N/A	N/A	N/A	N/A	N/A	N/A
Mercury	7.80E-10	0.0000015	0.0000011	0.0000015	0.0000063	0.000025
Naphthalene	6.33E-07	0.001	0.001	0.001	0.0051	0.020
Nickel	N/A	N/A	N/A	N/A	N/A	N/A
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.0038	0.015
Polycyclic Organic Matter	N/A	N/A	N/A	N/A	N/A	N/A
Propylene Oxide	2.86E-05	0.056	0.039	0.055	0.2305	0.922
Selenium	N/A	N/A	N/A	N/A	N/A	N/A
Toluene	6.80E-05	0.133	0.092	0.131	0.5481	2.192
Xylene	6.51E-05	0.127	0.088	0.125	0.5247	2.099
Maximum Individual HAP		0.223	0.154	0.219	0.919	3.675
Total HAPs		0.717	0.495	0.704	2.955	11.821

[(a)] - All emission factors except mercury, Frame Type CTs >40 MW from EPA AP-42, Section 3.1 Database, April 2000.
[(b)] - Mercury emission factor, Florida Coordinating Group (FCG), 1995.

Sources: ECT, 2000.
Siemens Westinghouse, 2000.
Calpine, 2000.

Table C.5. Calpine Blue Heron
Duct Burner (DB): Hazardous Air Pollutants

Parameter	Units	Annual Profile		
		100%		
Maximum DB Hourly Fuel Flow:	10^6 scf/hr	0.274	N/A	N/A
Maximum Annual Hours:	hrs/yr	8,760	N/A	N/A

Pollutant	Emission Factor [a], [b] (lb/10^6 scf)	Emission Rates (Per DB)				DB 1-4
		100% (lb/hr)			Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	N/A	N/A			N/A	N/A
Acetaldehyde	N/A	N/A			N/A	N/A
Acrolein	N/A	N/A			N/A	N/A
Arsenic	2.00E-04	0.000055			0.00024	0.00096
Benzene	2.10E-03	0.00057			0.0025	0.0101
Beryllium	1.20E-05	0.0000033			0.000014	0.000058
Cadmium	1.10E-03	0.00030			0.0013	0.0053
Chromium	1.40E-03	0.00038			0.0017	0.0067
Cobalt	8.40E-05	0.000023			0.00010	0.00040
Dichlorobenzene	1.20E-03	0.00033			0.0014	0.00575
Ethylbenzene	N/A	N/A			N/A	N/A
Formaldehyde	7.50E-02	0.021			0.090	0.36
Hexane	1.80E+00	**0.49**			**2.16**	**8.63**
Lead	5.00E-04	0.00014			0.00060	0.0024
Manganese	3.80E-04	0.00010			0.00046	0.0018
Mercury	2.60E-04	0.000071			0.00031	0.0012
Naphthalene	6.10E-04	0.00017			0.00073	0.0029
Nickel	2.10E-03	0.00057			0.0025	0.010
Polycyclic Aromatic Hydrocarbons	N/A	N/A			N/A	N/A
Polycyclic Organic Matter	8.82E-05	0.000024			0.00011	0.00042
Propylene Oxide	N/A	N/A			N/A	N/A
Selenium	2.40E-05	0.0000066			0.000029	0.00012
Toluene	3.40E-03	0.00093			0.0041	0.016
Xylene	N/A	N/A			N/A	N/A
Maximum Individual HAP		0.493			2.158	8.630
Total HAPs		0.517			2.264	9.054

[a] - All organic emission factors from Table 1.4-3., EPA AP-42, July 1998.
[b] - All metallic emission factors from Table 1.4-4., EPA AP-42, July 1998.

Sources: ECT, 2000.
Siemens Westinghouse, 2000.
Calpine, 2000.

Table C.6. Calpine Blue Heron
CTG/DB Annual Hazardous Air Pollutants Emission Rates

Pollutant	CTG Emissions (ton/yr)	DB Emissions (ton/yr)	Total Emissions (ton/yr)
1,3-Butadiene	0.002	N/A	0.0021
Acetaldehyde	1.476	N/A	1.4763
Acrolein	0.192	N/A	0.1918
Arsenic	N/A	0.0010	0.0010
Benzene	0.627	0.0101	0.6369
Beryllium	N/A	0.0001	0.0001
Cadmium	N/A	0.0053	0.0053
Chromium	N/A	0.0067	0.0067
Cobalt	N/A	0.0004	0.0004
Dichlorobenzene	N/A	0.0058	0.0058
Ethylbenzene	0.781	N/A	0.7810
Formaldehyde	**3.905**	0.3596	4.2645
Hexane	N/A	**8.6301**	**8.6301**
Lead	N/A	0.0024	0.0024
Manganese	N/A	0.0018	0.0018
Mercury	0.000027	0.0012	0.0013
Naphthalene	0.022	0.0029	0.0246
Nickel	N/A	0.0101	0.0101
Polycyclic Aromatic Hydrocarbons (PAHs)	0.016	N/A	0.0161
Polycyclic Organic Matter (POMs)	N/A	0.0004	0.0004
Propylene Oxide	0.980	N/A	0.9796
Selenium	N/A	0.0001	0.0001
Toluene	2.329	0.0163	2.3455
Xylene	2.230	N/A	2.2299
Maximum Individual HAP	3.905	8.630	8.630
Total HAPs	12.560	9.054	21.614

Source: ECT, 2000.

Table C-7.A. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile A
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	8,760	97.4	426.8	172.0	753.4	11.6	50.8
		Totals	**8,760**	**N/A**	**426.8**	**N/A**	**753.4**	**N/A**	**50.8**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	8,760	71.1	311.2	31.7	139.0	0.118	0.52	5.8	25.5
		Totals	**8,760**	**N/A**	**311.2**	**N/A**	**139.0**	**N/A**	**0.52**	**N/A**	**25.5**

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-7.B. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile B
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	5,880	97.4	286.5	172.0	505.7	11.6	34.1
CTG/HRSG1-4	20	4	2,880	112.3	161.7	709.0	1,021.0	69.4	99.9
		Totals	**8,760**	**N/A**	**448.2**	**N/A**	**1,526.6**	**N/A**	**134.0**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	5,880	71.1	208.9	31.7	93.3	0.118	0.35	5.8	17.1
CTG/HRSG1-4	20	4	2,880	90.3	130.1	35.9	51.6	0.134	0.19	6.6	9.5
		Totals	**8,760**	**N/A**	**339.0**	**N/A**	**145.0**	**N/A**	**0.54**	**N/A**	**26.6**

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-7.C. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile C
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	5,700	97.4	277.7	172.0	490.2	11.6	33.1
CTG/HRSG1-4	9	4	1,500	67.2	50.4	588.0	441.0	20.0	15.0
CTG/HRSG1-4	19	4	1,560	95.8	74.7	420.0	327.6	11.6	9.0
		Totals	**8,760**	**N/A**	**402.8**	**N/A**	**1,258.8**	**N/A**	**57.1**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	5,700	71.1	202.5	31.7	90.4	0.118	0.34	5.8	16.6
CTG/HRSG1-4	9	4	1,500	52.6	39.5	21.9	16.4	0.082	0.06	4.0	3.0
CTG/HRSG1-4	19	4	1,560	64.1	50.0	31.2	24.3	0.116	0.09	5.7	4.5
		Totals	**8,760**	**N/A**	**292.0**	**N/A**	**131.2**	**N/A**	**0.49**	**N/A**	**19.6**

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-7.D. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Profile D
Criteria Air Pollutants and Sulfuric Acid Mist

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	4,380	97.4	213.4	172.0	376.7	11.6	25.4
CTG/HRSG1-4	9	4	1,500	67.2	50.4	588.0	441.0	20.0	15.0
CTG/HRSG1-4	20	4	2,880	112.3	161.7	709.0	1,021.0	69.4	99.9
		Totals	**8,760**	**N/A**	**425.5**	**N/A**	**1,838.6**	**N/A**	**140.3**

Source	Case	No. of CTG/HRSGs	Annual Operations (hrs/yr)	Emission Rates							
				PM/PM_{10}		SO_2		Lead		H_2SO_4	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG/HRSG1-4	7	4	4,380	71.1	155.6	31.7	69.5	0.118	0.26	5.8	12.8
CTG/HRSG1-4	9	4	1,500	52.6	39.5	21.9	16.4	0.082	0.06	4.0	3.0
CTG/HRSG1-4	20	4	2,880	90.3	130.1	35.9	51.6	0.134	0.19	6.6	9.5
		Totals	**8,760**	**N/A**	**325.2**	**N/A**	**137.6**	**N/A**	**0.51**	**N/A**	**15.8**

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-7.E. Calpine Blue Heron
CTG/HRSG Annual Emission Rates - Summary
Criteria Air Pollutants and Sulfuric Acid Mist

Annual Profile	Annual Emissions (ton/yr)						
	NO_x	CO	VOC	PM/PM_{10}	SO_2	Pb	H_2SO_4
A	426.8	753.4	50.8	311.2	139.0	0.52	25.5
B	**448.2**	1,526.6	134.0	**339.0**	**145.0**	**0.54**	**26.6**
C	402.8	1,526.6	57.1	292.0	131.2	0.49	19.6
D	425.5	**1,838.6**	**140.3**	325.2	137.6	0.51	15.8
Maximums	448.2	1,838.6	140.3	339.0	145.0	0.54	26.6

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-8. Calpine Blue Heron
CTG/HRSG Exhaust Flow Rates (Per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %																					
	MW	100 % Load														70 % Load				60 % Load			
Component	(lb/mole)	20 °F	20 °F	20 °F	20 °F	59 °F	72 °F	72 °F	72 °F	95 °F	95 °F	95 °F	95 °F	95 °F	95 °F	20 °F	59 °F	72 °F	95 °F	20 °F	59 °F	72 °F	95 °F
	Case	1	2	3	4	7	10	11	12	15	16	17	18	19	20	5	8	13	21	6	9	14	22
Ar	39.944	0.94	0.93	0.90	0.90	0.93	0.92	0.92	0.91	0.90	0.86	0.90	0.89	0.85	0.84	0.94	0.94	0.93	0.90	0.94	0.94	0.93	0.90
N_2	28.013	74.91	74.49	71.89	71.51	74.37	73.54	73.47	73.02	71.80	68.18	71.69	71.22	68.07	67.66	75.17	74.63	73.82	72.10	75.14	74.56	73.77	72.10
O_2	31.999	12.50	11.30	11.65	10.50	12.51	12.31	12.28	10.97	11.87	10.81	11.82	10.44	10.76	9.46	13.25	13.25	13.11	12.76	13.16	13.07	12.97	12.77
CO_2	44.010	3.82	4.36	3.84	4.36	3.74	3.73	3.74	4.33	3.72	3.76	3.73	4.36	3.77	4.36	3.48	3.41	3.37	3.31	3.52	3.49	3.43	3.31
H_2O	18.015	7.83	8.92	11.71	12.73	8.44	9.49	9.59	10.76	11.72	16.39	11.86	13.08	16.54	17.67	7.16	7.77	8.77	10.92	7.23	7.94	8.90	10.92
	Totals	100.00	100.00	99.99	100.00	99.99	99.99	100.00	100.00	100.01	100.00	100.00	100.00	99.99	100.00	100.00	100.00	100.00	99.99	99.99	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.45	28.38	28.03	27.96	28.37	28.26	28.25	28.18	28.02	27.51	28.00	27.93	27.49	27.42	28.49	28.42	28.31	28.06	28.49	28.41	28.30	28.07
Exhaust Flow (lb/sec)		1,073.92	1,077.37	1,102.25	1,105.70	1,006.97	973.65	978.65	982.09	912.33	942.93	920.00	923.44	950.98	954.43	886.78	841.03	823.63	791.16	784.10	746.93	732.71	706.84
Exhaust Temp. (°F)		165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165	165
(K)		347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347	347
Ambient Temp. (°F)		20	20	20	20	59	72	72	72	95	95	95	95	95	95	20	59	72	95	20	59	72	95
(K)		266	266	266	266	288	295	295	295	308	308	308	308	308	308	266	288	295	308	266	288	295	308
Exhaust O_2 (Vol %, Dry)		13.56	12.40	13.20	12.03	13.66	13.60	13.58	12.30	13.45	12.93	13.41	12.02	12.89	11.49	14.27	14.37	14.37	14.32	14.19	14.20	14.24	14.34

B. Exhaust Flow Rates

	100 % Load														70 % Load				60 % Load			
	20 °F	20 °F	20 °F	20 °F	59 °F	72 °F	72 °F	72 °F	95 °F	95 °F	95 °F	95 °F	95 °F	95 °F	20 °F	59 °F	72 °F	95 °F	20 °F	59 °F	72 °F	95 °F
Case	1	2	3	4	7	10	11	12	15	16	17	18	19	20	5	8	13	21	6	9	14	22
ACFM	1,032,997	1,038,875	1,076,372	1,082,142	971,235	942,946	948,014	953,892	891,091	938,061	899,135	905,012	946,745	952,528	851,718	809,830	796,239	771,528	753,283	719,504	708,570	689,218
Stack Diameter (ft)	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
Stack Area (ft^2)	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5	283.5
Velocity (fps)	60.7	61.1	63.3	63.6	57.1	55.4	55.7	56.1	52.4	55.1	52.9	53.2	55.7	56.0	50.1	47.6	46.8	45.4	44.3	42.3	41.7	40.5
Velocity (m/s)	18.5	18.6	19.3	19.4	17.4	16.9	17.0	17.1	16.0	16.8	16.1	16.2	17.0	17.1	15.3	14.5	14.3	13.8	13.5	12.9	12.7	12.3
SCFM, Dry[1]	804,267	799,303	802,760	797,705	751,177	720,933	724,008	719,043	664,502	662,523	669,437	664,472	667,457	662,412	667,948	630,925	613,611	580,555	590,306	559,520	545,272	518,619

[1] At 68 °F.

Sources: *Calpine, 2000.*
ECT, 2000.
Siemens Westinghouse, 2000.

Table C-9. Calpine Blue Heron
CTG/HRSG Hourly Fuel Flow Rates (Per CTG/HRSG)

	100 % Load														70 % Load				60 % Load			
	20 °F	20 °F	20 °F	20 °F	59 °F	72 °F	72 °F	72 °F	95 °F	95 °F	95 °F	95 °F	95 °F	95 °F	20 °F	59 °F	72 °F	95 °F	20 °F	59 °F	72 °F	95 °F
Case	1	2	3	4	7	10	11	12	15	16	17	18	19	20	5	8	13	21	6	9	14	22
Heat Input - HHV[1] (MMBtu/hr)	2,122	2,411	2,226	2,515	1,955	1,892	1,906	2,195	1,782	1,898	1,803	2,092	1,920	2,209	1,581	1,471	1,431	1,365	1,426	1,350	1,308	1,227
Heat Input - LHV[1] (MMBtu/hr)	1,911	2,171	2,004	2,265	1,760	1,714	1,717	1,977	1,604	1,709	1,623	1,883	1,729	1,989	1,424	1,325	1,288	1,229	1,284	1,216	1,178	1,105
Fuel Rate[2] (lb/hr)	91,079	103,483	95,541	107,945	83,913	81,209	81,795	94,199	76,478	81,480	77,379	89,783	82,426	94,830	67,870	63,138	61,425	58,586	61,200	57,955	56,153	52,683
Fuel Rate (lb/sec)	25.300	28.745	26.539	29.985	23.309	22.558	22.721	26.166	21.244	22.633	21.494	24.940	22.896	26.342	18.853	17.538	17.063	16.274	17.000	16.099	15.598	14.634
Fuel Rate[3] (10^6 ft^3/hr)	2.009	2.283	2.108	2.381	1.851	1.792	1.805	2.078	1.687	1.798	1.707	1.981	1.819	2.092	1.497	1.393	1.355	1.293	1.350	1.279	1.239	1.162

[1] Includes 5.0 % margin.
[2] Based on natural gas heat content of 23,299 Btu/lb (HHV).
[3] Based on natural gas density of 0.04533 lb/ft^3.

Sources: ECT, 2000.
Calpine, 2000.
Siemens Westinghouse, 2000.

Table C-10. Calpine Blue Heron
CTG NSPS Subpart GG Limit (Per CTG)

Fuel	501F Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,240	9.749	0.0	110.8

Sources: ECT, 2000.
Siemens Westinghouse, 2000.

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

EG-ENG

EMISSION SOURCE TYPE

DIESEL ENGINES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Stationary Diesel Engine
Emission Control Method(s)/ID No.(s):	None
Emission Point Description:	1,400 kW Emergency Generator Diesel Engine

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/hr)

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

Source: ECT, 2000.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	250	hrs/yr
Fuel Flow:	29,200	gal/yr
Fuel Flow:	*116.8*	*gal/hr*
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	16.47	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
NO_x	37.24	37.24	4.66
CO	8.34	8.34	1.04
TOC	1.48	1.48	0.19
SO_2	0.820	0.82	0.10
PM	1.380	1.38	0.17
PM_{10}	1.380	1.38	0.17

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2000.
Fuel Flow Rate (gal/yr)	Calpine, 2000.
Emission Factors (all except TOC)	Calpine, 2000.
Emission Factor (TOC)	AP-42, Table 3.4-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Baldwin	Date:	Aug-00
Data Entered by:	T.Davis	Date:	Aug-00
Reviewed by:	T. Baldwin	Date:	Aug-00

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

FW-ENG

EMISSION SOURCE TYPE

DIESEL ENGINES - CRITERIA POLLUTANTS

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Stationary Diesel Engine
Emission Control Method(s)/ID No.(s):	None
Emission Point Description:	Fire Water Pump Diesel Engine

EMISSION ESTIMATION EQUATIONS

Emission (lb/hr) = Emission Factor (lb/hr)

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

Source: ECT, 2000.

INPUT DATA AND EMISSIONS CALCULATIONS

Operating Hours:	100	hrs/yr
Fuel Flow:	2,000	gal/yr
Fuel Flow:	20.0	gal/hr
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	2.82	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	(tpy)
NO_x	7.41	7.41	0.37
CO	1.75	1.75	0.09
TOC	1.02	1.02	0.05
SO_2	0.140	0.14	0.007
PM	0.130	0.13	0.007
PM_{10}	0.130	0.13	0.007

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2000.
Fuel Flow Rate (gal/yr)	Calpine, 2000.
Emission Factors (all except TOC)	Calpine, 2000.
Emission Factor (TOC)	AP-42, Table 3.3-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Baldwin	Date:	Aug-00
Data Entered by:	T.Davis	Date:	Aug-00
Reviewed by:	T. Baldwin	Date:	Aug-00

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

MAIN-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Main Cooling Towers
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	North and South Main Cooling Towers

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_{10}/PM Fraction

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

Source: ECT, 2000.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	9	
Recirculating Water Flow Rate:	150,000	gal/min
Drift Loss Rate:	0.002	%
Total Dissolved Solids (TDS):	8,200	ppmw
PM_{10}/PM Fraction:	0.60	
Number of Towers:	2	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	1.37	5.99	24.63	107.90
PM_{10}	0.821	3.60	14.78	64.74

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2000.
Recirculating Water Flow Rate (gpm)	Calpine, 2000.
Drift Loss Rate (%)	Calpine, 2000.
PM_{10}/PM Fraction:	Marley Cooling Tower, 2000.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Baldwin	Aug-00
Data Entered by:	T.Davis	Aug-00
Reviewed by:	T. Baldwin	Aug-00

POTENTIAL EMISSION INVENTORY WORKSHEET

Calpine Blue Heron

WWT-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Wastewater Cooling Towers
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	Wastewater 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_{10}/PM Fraction

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

Source: ECT, 2000.

INPUT DATA AND EMISSIONS CALCULATIONS

Cooling Tower Data (Per Tower)

Operating Hours:	8,760	hrs/yr
Number of Cells:	3	
Recirculating Water Flow Rate:	5,000	gal/min
Drift Loss Rate:	0.0005	%
Total Dissolved Solids (TDS):	104,280	ppmw
PM_{10}/PM Fraction:	0.80	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.44	1.91	1.31	5.72
PM_{10}	0.348	1.52	1.04	4.57

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	Calpine, 2000.
Recirculating Water Flow Rate (gpm)	Calpine, 2000.
Drift Loss Rate (%)	Calpine, 2000.
PM_{10}/PM Fraction:	Marley Cooling Tower, 2000.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	T.Baldwin	Aug-00
Data Entered by:	T.Davis	Aug-00
Reviewed by:	T. Baldwin	Aug-00

ATTACHMENT D

CONTROL TECHNOLOGY VENDOR QUOTES

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**September 8, 2000**	**NO. PAGES**	**3**
TO:	**ECT** **ATTN: Tom Davis** **ENGELHARD** **ATTN: Nancy Ellison**	**via e-mail**	
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **ECT 000105-0300-1100 / Calpine-Blue Heron**
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928

We provide Engelhard Budgetary Proposal EPB00928 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems per your e-mail request of August 24, 2000.

Our Proposal is based on:

- CO Catalyst for 90% CO reduction;
- SCR Catalyst for NOx reduction from given inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 9 ppmvd @ 15% O_2;
- Assumed HRSG inside liner dimensions of 67 ft. H x 32 ft. W;
- Assumed 19% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth

Frederick A. Booth
Senior Sales Engineer

ENGELHARD

ECT 000105-0300-1100
Calpine Blue Heron
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928
September 8, 2000

CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.
Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (19% Sol.) Ammonia to skid
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
  - Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
  - Blowers (on/off/flow indicators)
  - Air/ammonia flow indicator and controller
  - System pressure indicators
  - Main power disconnect switch

BUDGET PRICES: Per Turbine See Performance data

Excluded from Scope of Supply:
Ammonia storage and pumping
Any transitions to and from reactor
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Internally insulated reactor Housing (HRSG Casing)
Any interconnecting field piping or wiring
Utilities
All Monitors

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	• Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

CO / SCR SYSTEM DESIGN BASIS:

Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within $\pm$15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range $\pm 20^{O}F$ at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	90% Reduction
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2 (NG)
NH_3 Slip:	9 ppmvd @ 15%O_2
HRSG Cross Section	67 ft. H x 32 ft. W

ENGELHARD

ECT 000105-0300-1100
Calpine Blue Heron
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00928
September 8, 2000

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	
TURBINE EXHAUST FLOW, lb/hr	3,980,503
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	71.51
O2	10.50
CO2	4.36
H2O	12.73
Ar	0.90
GIVEN: TURBINE CO, ppmvd @ 15% O2	37
CALC.: TURBINE CO, lb/hr	193.2
GIVEN: TURBINE NOx, ppmvd @ 15%O2	25
CALC.: TURBINE NOx, lb/hr	212.5
CALC. GAS MOL. WT.	27.97
GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650
DESIGN REQUIREMENTS	
CO CATALYST CO OUT, ppmvd @ 15% O2	3.7
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5
NH3 SLIP, ppmvd @ 15% O2	9
GUARANTEED PERFORMANCE DATA	
CO CATALYST CO CONVERSION, % - Min.	90.0%
CO OUT, lb/hr - Max.	19.3
CO OUT, ppmvd @ 15% O2 - Max.	3.7
CO PRESSURE DROP, "WG - Max.	1.0
SCR CATALYST NOx CONVERSION, % - Min.	85.9%
NOx OUT, lb/hr - Max.	30.1
NOx OUT, ppmvd @ 15% O2 - Max.	3.5
EXPECTED AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	505.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	9
SCR PRESSURE DROP, "WG - Max.	2.0
CO SYSTEM	**$880,000**
REPLACEMENT CO CATALYST MODULES	**$770,000**
SCR SYSTEM	**$1,678,000**
REPLACEMENT SCR CATALYST MODULES	**$1,178,000**

ATTACHMENT E

DISPERSION MODELING FILES


CALPINE
BLUE HERON
ENERGY CENTER
ECT
Environmental Consulting & Technology, Inc.