EL PASO ENERGY

March 26, 2001

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BUREAU OF AIR REGULATION

Mr. A. A. Linero, P.E.
Administrator, New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS # 5505
Tallahassee, Florida 32399-2400

Re: El Paso Merchant Energy Company
Manatee Energy Center
Air Construction Permit Application

Dear Mr. Linero:

El Paso Merchant Energy Company (EPMEC) is planning to construct, own, and operate a new electric power generating plant in Manatee County, Florida. The new power plant, designated as the Manatee Energy Center (MEC), will be a combustion turbine generator (CTG) facility comprised of one combined cycle (CC) CTG with a nominal generating capacity of 250 megawatts (MW) and two simple cycle (SC) CTGs, each with a nominal generating capacity of 175 MW. The CC unit will consist of one nominal 175 MW CTG, one unfired heat recovery steam generator, and one steam turbine generator constrained to generate less than 75 MW. Total MEC generating capacity will be a nominal 600 MW. The MEC CTGs will be fired exclusively with natural gas. MEC will be located in Manatee County approximately 0.6 miles northeast of Buckeye Road and U.S. Highway 41.

Seven copies of an Application for Air Permit – Title V Source, together with a check in the amount of $7,500 as payment of the required permit processing fee, are enclosed for your review. Three of the applications include a CD-ROM containing the dispersion modeling files. Your expeditious processing of the EPMEC air permit application will be appreciated. Please contact me at 713/877-7023 if there are any questions.

Sincerely,

EL PASO MERCHANT ENERGY COMPANY

K. Ravishankar

Krish Ravishankar
Environmental Manager

cc: Ms. Karen Collins, Manatee County DEM

Enclosures

AIR CONSTRUCTION PERMIT APPLICATION

MANATEE ENERGY CENTER MANATEE COUNTY, FLORIDA

Prepared for:

elpaso

Prepared by:

ECT

Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 000888-0300

March 2001

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

El Paso Merchant Energy Company (EPMEC) is planning to construct, own, and operate a new electric power generating plant in Manatee County, Florida. The new power plant, designated as the Manatee Energy Center (MEC), will be a natural gas-fired combustion turbine generator (CTG) facility comprised of one combined cycle (CC) CTG with a nominal generating capacity of 250 megawatts (MW) and two simple cycle (SC) CTGs, each with a nominal generating capacity of 175 MW. The CC unit will consist of one nominal 175 MW CTG, one unfired heat recovery steam generator (HRSG), and one steam turbine generator (STG) constrained to generate less than 75 MW. Total MEC generating capacity will be a nominal 600 MW. The CTGs will include provisions for inlet air evaporative cooling (SC and CC CTGs) and steam mass flow augmentation (CC CTG). Ancillary emission sources include a fresh water cooling tower and two emergency diesel engines.

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 appendices, constitutes EPMEC'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.

MEC 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, MEC 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).
- Section 6.0 describes the dispersion modeling methodology.
- Section 7.0 provides dispersion modeling results.
- Section 8.0 discusses current ambient air quality in the MEC vicinity and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 provides an assessment of impacts on the Chassahowitzka National Wildlife Refuge (NWR) Class I area.

Appendices A through E provide the FDEP Application for Air Permit—Title V Source, CTG vendor information, emission rate calculations, control technology vendor data, and FDEP correspondence regarding applicability of the Florida Electrical Power Plant Siting Act, respectively. All dispersion modeling input and output files for the ambient impact analysis are provided in CD-ROM format in Appendix F.

1.2 SUMMARY

MEC will consist of: (a) one nominal 175 MW General Electric 7FA CTG, one unfired HRSG, and one STG constrained to generate less than 75 MW; i.e., one "1 by 1 by 1" CC configuration, and (b) two nominal 175 MW General Electric 7FA CTGs operating in SC mode. The CTGs will include provisions for inlet air evaporative cooling (SC and CC) and steam mass flow augmentation (CC CTG only). MEC will have a total nominal generation capacity of 600 MW. Ancillary equipment includes one five-cell, fresh water cooling tower, one emergency electric generator diesel engine, one emergency fire water pump diesel engine, and water treatment and storage facilities. The CTGs 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 MEC construction start date is April 2002. The projected date for the MEC to begin commercial operation is June 2003, following initial equipment startup and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, MEC will have the potential to emit 391.3 tpy of nitrogen oxides (NO_x), 349.0 tpy of carbon monoxide (CO), 180.9 tpy of particulate matter (PM), 180.2 tpy of particulate matter/particulate matter less than or equal to 10 micrometers (PM_{10}), 68.8 tpy of sulfur dioxide (SO_2), 28.8 tpy of volatile organic compounds (VOCs), and 0.3 tpy of lead. Regarding noncriteria pollutants, MEC will potentially emit 10.4 tpy of sulfuric acid (H_2SO_4) mist, and 0.000013 tpy of mercury. Based on these annual emission rate potentials, NO_x, CO, 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 BACT for PM/PM_{10}. The CTGs 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.
- Use of dry low-NO_x (DLN) combustors, followed by selective catalytic reduction (SCR), is proposed as BACT for NO_x for the MEC's CC CTG unit. For all operating scenarios, CC CTG NO_x exhaust concentrations will not exceed 3.5 parts per million by volume, dry (ppmvd), corrected to 15 percent oxygen. 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 $24,187 and $142,512, respectively. Since these costs exceed values previously determined by FDEP to be cost effective, installation of SCONO$_x$™ control technology is considered to be economically unreasonable. An additional NO_x BACT consideration pertinent to MEC 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 MEC, which will use natural gas as the only fuel source.

- Dry low-NO_x (DLN) combustor technology is proposed as BACT for NO_x for the two MEC SC CTG units. For all operating scenarios, SC CTG NO_x exhaust concentrations will not exceed 9.0 ppmvd, corrected to 15 percent oxygen. This concentration is consistent with recent FDEP BACT determinations for natural gas-fired CTGs. Average cost effectiveness of high temperature (i.e., greater than 750°F) SCR was determined to be $22,052. Because this cost exceeds values previously determined by FDEP to be cost effective, installation of "hot" SCR control technology is considered to be economically unreasonable.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as BACT for CO and VOCs for the CTGs. At baseload operation and annual average temperature conditions, maximum CTG CO and VOC exhaust concentrations are projected to be 7.4 and 1.3 ppmvd at 15 percent O_2, respectively, for both CC and SC modes. At baseload operation, annual average temperature, and steam mass flow augmentation, the CC CTG CO and VOC exhaust concentrations are projected to be 11.7 and 1.5 ppmvd at 15 percent O_2, respectively. These concentrations are consistent with prior FDEP BACT determinations for CTGs (e.g., City of Tallahassee Purdom Unit 8, Lakeland Utilities McIntosh Unit 5, and Santa Rose Energy). Average cost effectiveness of a CO oxidation catalyst control system was determined to be $2,475 and $8,981 per ton of CO for the CC CTG/HRSG and SC CTGs, respectively. Because these costs exceed values previously determined by FDEP to be cost effective, installation of oxidation catalyst control technology 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.
- MEC 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. MEC 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.

- MEC is projected to emit NO_x, CO, PM/PM_{10}, SO_2, and H_2SO_4 mist in greater than significant amounts; the PSD significant emission rates are provided in Section 3.0, Table 3-2 of this document. The ambient impact analysis demonstrates that project impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, MEC qualifies for the Section 62-212.400, Table 212.400-3, F.A.C., exemption from PSD preconstruction ambient air quality monitoring requirements for all PSD pollutants.
- The ambient impact analysis demonstrates that project impacts for all pollutants emitted in significant amounts will be below the PSD Class II significant impact levels defined in Rule 62-210.259(259), F.A.C., and below the U.S. Environmental Protection Agency (EPA) defined PSD Class I significant impact levels; the EPA significant levels are provided in Section 4.0, Table 4-3 of this document. Accordingly, multi-source interactive assessments of National Ambient Air Quality Standards (NAAQS) attainment and PSD Class I and II increment consumption were not required.
- Based on refined dispersion modeling, MEC will not cause nor contribute to a violation of any NAAQS, Florida Ambient Air Quality Standards (AAQS), or PSD increments 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 FDEP draft ambient reference concentration for H_2SO_4 mist are provided in Section 7.4 of this document.
- The ambient impact analysis also demonstrates that project pollutant impacts will be below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Chassahowitzka NWR) is located approximately 110 kilometers (km) north of the MEC site. Based on refined Calpuff dispersion modeling, visibility and deposition impacts on this Class I area will be below the applicable National Park Service (NPS) significance levels; the NPS significance levels are discussed in Section 10.0 of this document.

- Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shutdown, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because CC 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 MEC CC CTG: (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., 50 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

MEC will be located in Manatee County approximately 0.6 miles northeast of Buckeye Road and U.S. Highway 41 (U.S. 41) directly northeast of the town of Piney Point. The plant site is bordered on the north and east by agricultural land, and on the west and south by an existing phosphate processing complex. MEC site location and vicinity maps are provided in Figures 2-1 and 2-2, respectively.

Major components of the MEC include:

- One CC unit comprised of one General Electric 7FA CTG, one unfired HRSG, and one STG. This CC configuration is commonly referred to as a "1 by 1 by 1" configuration with the values referring to the number of CTGs, HRSGs, and STGs, respectively.
- Two General Electric 7FA CTGs operating in SC mode.
- One 5-cell mechanical draft, fresh water cooling tower.
- One 2,600-horsepower (HP) emergency diesel-fired electrical generator.
- One 250-HP emergency diesel-fired fire water pump.
- Ancillary equipment, including raw and demineralized water storage tanks.

The CTGs will be General Electric 7FA units. Each CTG will have provisions for inlet air evaporative cooling (SC and CC CTGs) and steam mass flow augmentation (CC CTG only). Each CTG will be capable of producing a nominal 175 MW of electricity. The CC unit HRSG will be unfired; i.e., will not be operated with supplemental duct burners. It will furnish steam to the STG for the additional generation of electricity. The STG will be operationally constrained to generate less than 75 MW. The CTGs will be fired exclusively with pipeline-quality natural gas.

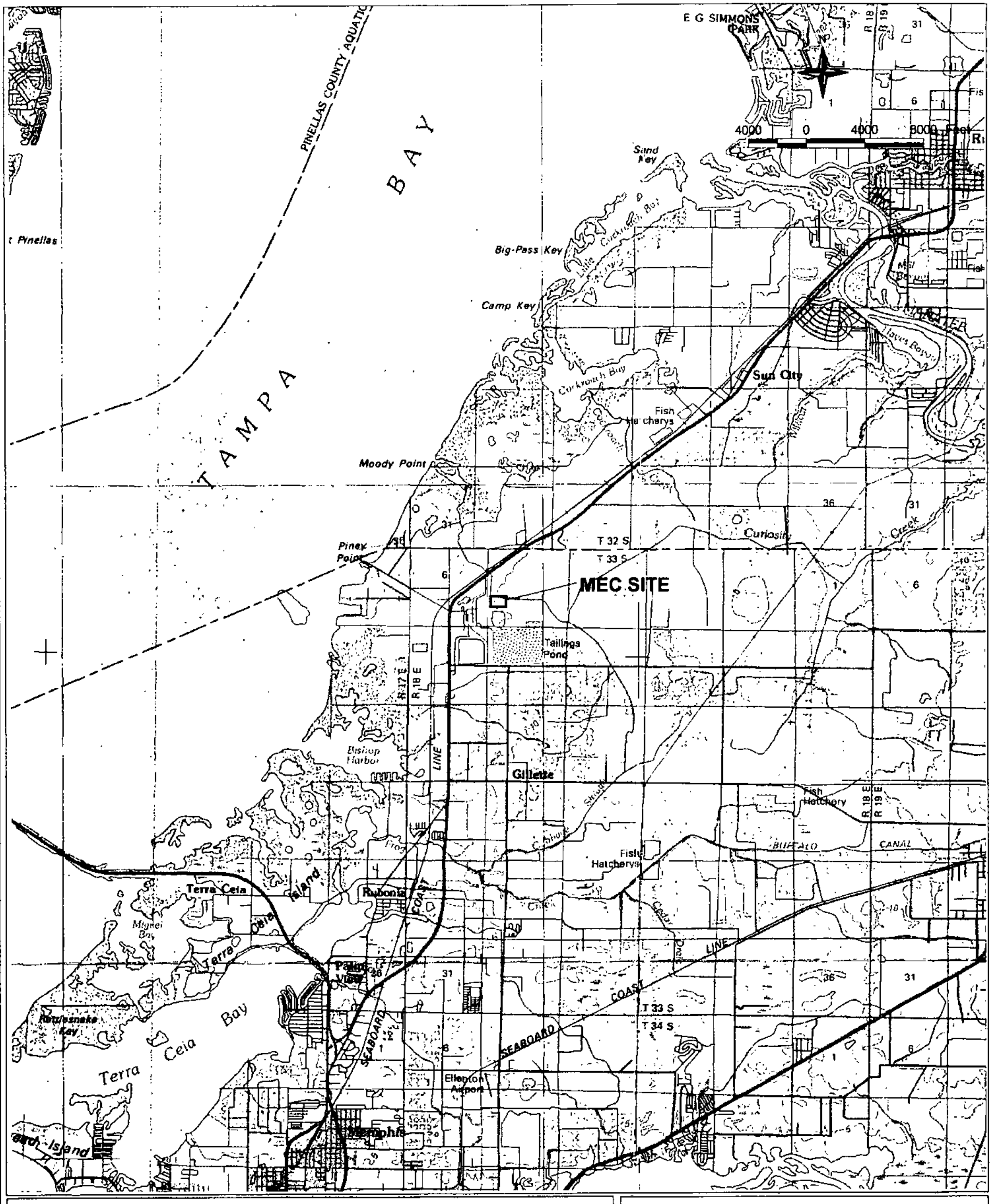

FIGURE 2-1.
MANATEE ENERGY CENTER SITE LOCATION MAP
SITE LOCATION MAP

Sources: USGS 100,000 Scale Quad: St. Petersburg, FL, 1981; ECT, 2001.

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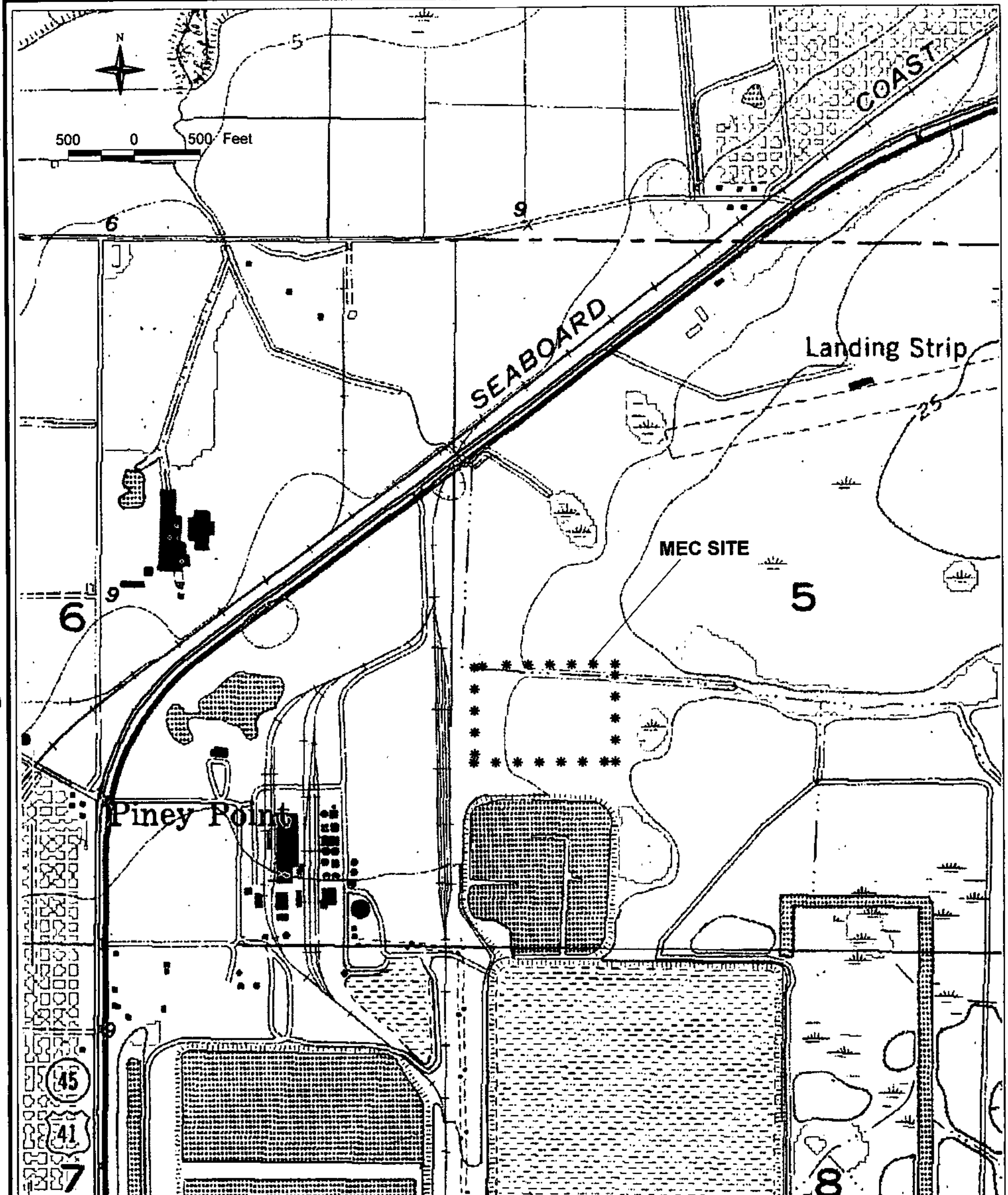

FIGURE 2-2.

MANATEE ENERGY CENTER SITE VICINITY MAP

Sources: USGS Quad: Cockroach Bay, FL, 1981; ECT, 2001.

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The MEC CC CTG/HRSG unit will be capable of continuous operation at baseload for up to 8,760 hours per year (hr/yr). The two SC CTGs will each be capable of continuous operation at baseload for up to 5,000 hr/yr. To provide flexibility in operations, EPMEC requests that the Department permit constraint on SC CTG operations be expressed in total annual fuel heat input for the two SC CTGs instead of operating hours. Specifically, a permit limit of 9,009,347 million British thermal units per year (MMBtu/yr), higher heating value (HHV), for each of the two SC CTGs is requested. This heat input limit is based on a SC CTG annual operating profile of: (a) 1,000 hr/yr at baseload operation and 35°F ambient air temperature (representative winter temperature), (b) 3,000 hr/yr at baseload operation and 73°F ambient air temperature (average annual temperature), and (c) 1,000 hr/yr at baseload operation and 96°F ambient air temperature (representative summer temperature). The CTGs will normally operate between 50- and 100-percent load.

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

Emission control systems proposed for the CC CTG/HRSG unit include the use of DLN combustors, 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, pipeline quality natural gas to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions. Emission control systems proposed for the two SC CTGs include the use of DLN combustors for control of NO_x and the same CO, VOCs, PM/PM_{10}, SO_2, and H_2SO_4 mist emission control technologies described for the CC CTG/HRSG unit. High efficiency drift eliminators will be utilized to control PM/PM_{10} emissions from the mechanical draft, fresh water cooling tower.

A general site layout of the MEC showing facility property lines, major process equipment and structures, and the major emission points is presented in Figure 2-3. Access to the plant site will be provided via U.S. 41. The plant entrance will have security gates to control site access. The entire plant perimeter will be fenced at the plant boundary.

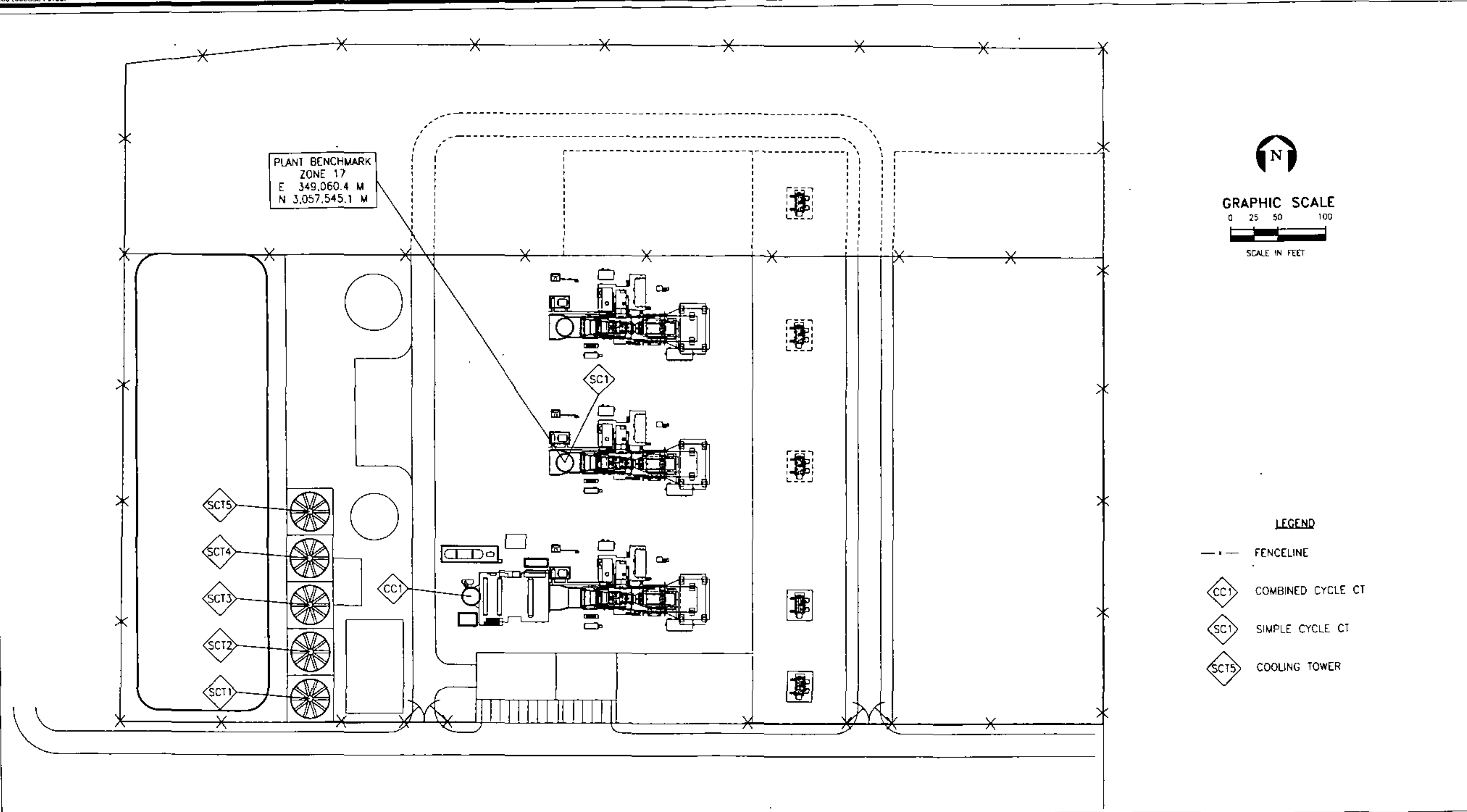

FIGURE 2-3.

GENERAL SITE LAYOUT

Sources: EPME, 2001; ECT, 2001.

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2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed MEC natural gas-fired power generation facility will include three nominal 175 MW CTGs, one HRSG operated without auxiliary firing, and one STG operationally constrained to generate less than 75 MW. Total MEC generation capacity will be a nominal 600 MW. A process flow diagram of MEC 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 that 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 gases. These high-pressure, hot gases expand and turn the CTG's turbine to produce rotary shaft power that is used to drive an electric generator as well as the CTG combustion air compressor.

The CC CTG will also utilize steam mass flow augmentation (i.e., the injection of steam into the CTG). Steam injection for mass flow augmentation is different than using steam injection in the CTG combustion zone for NO_x control. The MEC CTGs will rely upon DLN combustor technology to reduce NO_x emissions. The CC CTG/HRSG unit will also include SCR control technology to further reduce NO_x emissions.

The hot exhaust gases from the CC CTG next flow to the HRSG for steam production. The CC CTG will use a HRSG to recover exhaust heat from the CTG and produce steam to power the STG. The STG will drive an electric generator operationally constrained to generate less than 75 MW. Following reuse of the CTG exhaust waste heat by the HRSG,

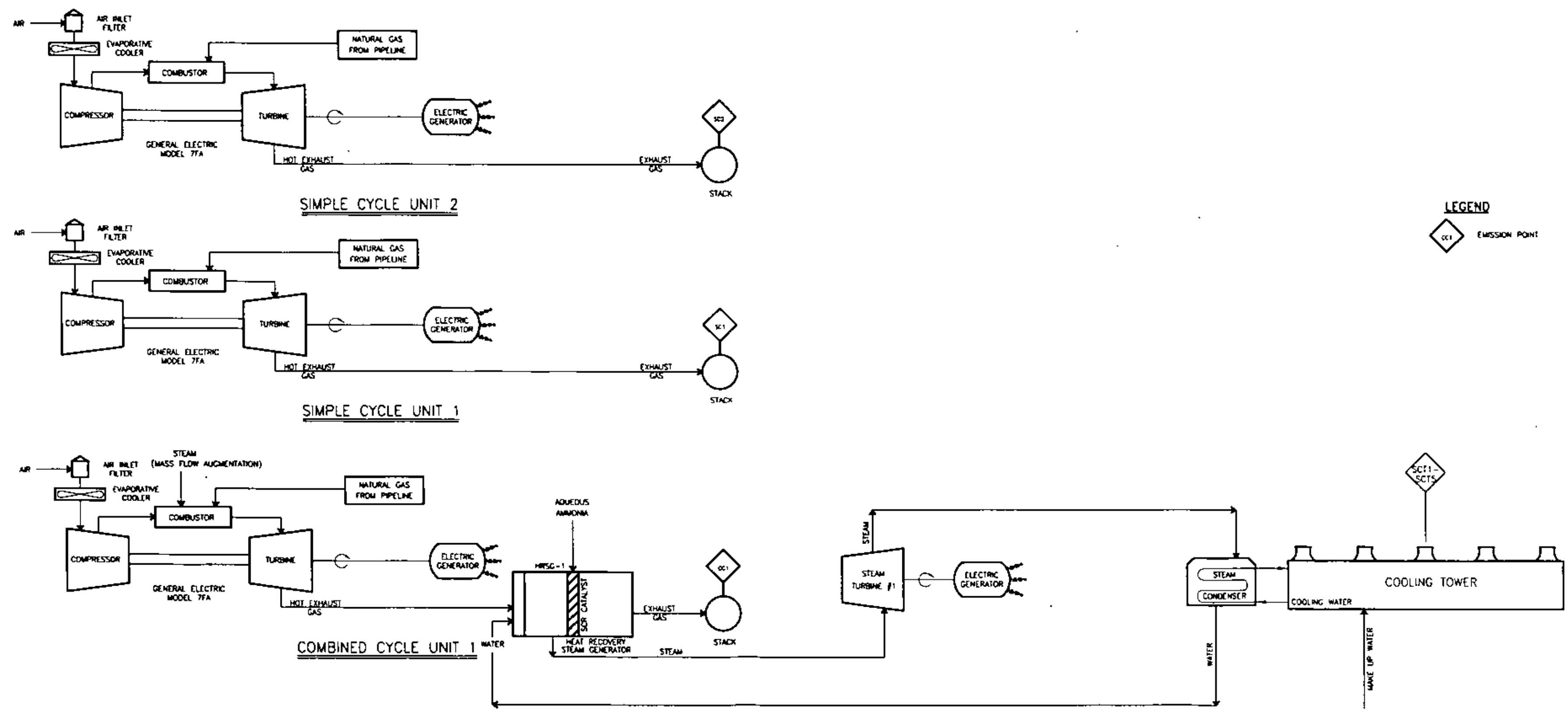

FIGURE 2-4.

PROCESS FLOW DIAGRAM

Source: ECT, 2001.

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the exhaust gases are discharged to the atmosphere. Exhaust gases from the SC CTGs, which do not include HRSGs, are discharged directly to the atmosphere.

After final design, the primary method to control steam turbine generator output will be the use of steam into the combustion turbine. Certain ambient conditions and transients shall further require steam turbine generator output control by additional systems. Control loops will be optimized to most effective yield the output desired. Systems such as steam bypass, economizer bypass, and cooling tower controls are some of the methods envisioned.

Normal operation is expected to consist of the one CC CTG/HRSG operating at baseload. The two SC CTGs will normally operate between 50 and 100 percent load depending on power demands. Alternate operating modes include reduced load (i.e., between 50 and 100 percent of baseload) operation for the CC CTG/HRSG unit depending on power demands and use of CTG inlet air evaporative cooling (or similar/equal systems such as "fogging") during warm ambient air temperature periods. CC CTG steam mass flow augmentation will occur normally as the principle method of STG output control. The CC CTG/HRSG unit is designed for continuous operation (i.e., 8,760 hr/yr) and may operate at up to a 100-percent annual capacity factor. Each SC CTG may operate with a natural gas heat input up to 9,009,347 MMBtu/yr, HHV.

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 CC 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 MEC CC CTG: (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., 50 percent load) and the STG is declared available for load changes.

The CTGs will utilize DLN combustion technology (SC and CC CTGs) and SCR (CC CTG only) to control NO_x air emissions. The exclusive use of low-sulfur natural gas in the CTGs will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CTG CO and VOC emissions. The 5-cell mechanical draft, fresh water cooling tower will be equipped with drift eliminators, achieving a drift loss rate of no more 0.0005 percent of circulating water flow rate.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant CC CTG/HRSG and SC CTG emission rates, respectively. Maximum hourly H_2SO_4 mist emission rates are summarized in Tables 2-3 and 2-4 for the CC CTG/HRSG and SC CTGs, respectively. Maximum hourly hazardous air pollutant (HAP) emission rates are summarized in Tables 2-5 and 2-6 for the CC CTG/HRSG and SC CTGs, respectively. 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.

For the CC CTG/HRSG unit, maximum hourly emission rates of PM_{10}, SO_2, H_2SO_4, and lead, in units of pounds per hour (lb/hr), are projected to occur for operations at winter temperatures (i.e., 35°F) and baseload. Maximum hourly emission rates of NO_x, CO, and VOC, in units of lb/hr, are projected to occur for operations at 59°F ambient air temperature, inlet air evaporative cooling, steam mass flow augmentation, and baseload. For the SC CTGs, maximum hourly emission rates of all pollutants, in units of lb/hr, are projected to occur for operations at winter temperatures and baseload. The bases for these emission rates are provided in Appendix C.

Table 2-7 presents projected maximum annualized criteria and HAP emissions for MEC based on an evaluation of expected annual operating profiles. The annual operating profiles are defined in Appendix C, Table C-1A (for the CC CTG/HRSG unit) and Table C-1B (for the SC CTGs). These profiles represent expected MEC operations on an

Table 2-1. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Four Ambient Temperatures (CC 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	35	20.0	2.52	7.7	0.8	23.8	3.5	31.0	7.6	3.0	1.3	0.029	0.0036
	59‡	20.0	2.52	7.6	0.8	23.6	3.5	48.4	11.8	3.4	1.5	0.029	0.0036
	73‡	20.0	2.52	7.5	0.8	23.0	3.5	47.0	11.7	3.3	1.5	0.028	0.0035
	96‡	20.0	2.52	7.1	0.8	22.0	3.5	44.7	11.7	3.0	1.4	0.027	0.0034
75	35	19.0	2.39	6.1	0.8	18.7	3.5	24.0	7.4	2.4	1.2	0.023	0.0029
	73	19.0	2.39	5.7	0.8	17.6	3.5	23.0	7.5	2.2	1.3	0.022	0.0027
	96	19.0	2.39	5.5	0.8	16.8	3.5	21.0	7.3	2.2	1.3	0.020	0.0026
50	35	19.0	2.39	4.9	0.8	14.9	3.5	20.6	7.9	2.1	1.4	0.018	0.0023
	73	19.0	2.39	4.6	0.8	14.0	3.5	19.0	7.9	1.8	1.3	0.017	0.0022
	96	19.0	2.39	4.3	0.8	13.3	3.5	18.0	7.9	1.8	1.4	0.016	0.0021

Note: ppmvd = parts per million by volume

* As measured by EPA Reference Methods 201A and 202.
† Corrected to 15-percent oxygen.
‡ Emission rates include evaporative cooling and steam mass flow augmentation.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table 2-2. Maximum Criteria Pollutant Emission Rates for Three Unit Loads and Three Ambient Temperatures (Per SC CTG)

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	35	18.3	2.31	7.7	0.8	61.0	9.0	31.0	7.5	3.0	1.3	0.029	0.0036
	73‡	18.3	2.31	7.2	0.8	57.0	9.0	28.0	7.4	2.8	1.3	0.029	0.0036
	96‡	18.3	2.31	6.8	0.8	54.0	9.0	27.0	7.3	2.6	1.3	0.028	0.0035
75	35	18.3	2.31	6.1	0.8	48.0	9.0	24.0	7.4	2.4	1.2	0.025	0.0032
	73	18.3	2.31	5.7	0.8	45.0	9.0	23.0	7.4	2.2	1.3	0.027	0.0034
	96	18.2	2.29	5.4	0.8	43.0	9.0	21.0	7.4	2.2	1.3	0.025	0.0031
50	35	18.2	2.29	4.9	0.8	38.0	9.0	20.0	7.7	2.0	1.3	0.023	0.0029
	73	18.2	2.29	4.6	0.8	36.0	9.0	19.0	7.8	1.8	1.3	0.022	0.0027
	96	18.2	2.29	4.4	0.8	34.0	9.0	18.0	8.0	1.8	1.4	0.020	0.0026

Note: ppmvd = parts per million by volume

* As measured by EPA Reference Methods 201A and 202.
† Corrected to 15-percent oxygen.
‡ Emission rates include evaporative cooling.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table 2-3. Maximum H_2SO_4 Emission Rates for Three Unit Loads and Four Ambient Temperatures (CC CTG/HRSG)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist lb/hr	H_2SO_4 mist g/s
100	35	1.41	0.177
	59*	1.41	0.177
	73*	1.37	0.173
	96*	1.31	0.165
75	35	1.13	0.142
	73	1.06	0.133
	96	1.00	0.126
50	35	0.90	0.114
	73	0.84	0.106
	96	0.80	0.101

Note: g/s = gram per second.

*Emission rates include evaporative cooling and steam mass flow augmentation.

Sources: EPMEC, 2001.
ECT, 2001.
General Electric, 2001.

Table 2-4. Maximum H_2SO_4 Emission Rates for Three Unit Loads and Three Temperatures (Per SC CTG)

Unit Load (%)	Ambient Temperature (°F)	H_2SO_4 mist lb/hr	H_2SO_4 mist g/s
100	35	0.94	0.118
	73*	0.88	0.111
	96*	0.83	0.105
75	35	0.75	0.094
	73	0.70	0.089
	96	0.67	0.084
50	35	0.60	0.076
	73	0.56	0.071
	96	0.53	0.067

Note: g/s = gram per second.

*Emission rates include evaporative cooling.

Sources: EPMEC, 2001.
ECT, 2001.
General Electric, 2001.

Table 2-5. Maximum HAP Pollutant Emission Rates for 100 Percent Load and Four Temperatures—CC CTG/HRSG

Unit Load (%)	Ambient Temp. (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	35	1.52E-04	1.91E-05	1.52E-03	1.91E-04	4.76E-05	6.00E-06	1.04E-03	1.31E-04	1.30E-04	1.64E-05	1.30E-09	1.64E-10
	59†	1.37E-04	1.72E-05	1.37E-03	1.72E-04	4.30E-05	5.42E-06	9.38E-04	1.18E-04	1.17E-04	1.48E-05	1.17E-09	1.48E-10
	73†	1.37E-04	1.72E-05	1.37E-03	1.72E-04	4.30E-05	5.42E-06	9.38E-04	1.18E-04	1.17E-04	1.48E-05	1.17E-09	1.48E-10
	96†	1.23E-04	1.56E-05	1.23E-03	1.56E-04	3.88E-05	4.89E-06	8.46E-04	1.07E-04	1.06E-04	1.33E-05	1.06E-09	1.33E-10

Unit Load (%)	Ambient Temp. (°F)	Mercury		Naphthalene		PAH		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	35	3.14E-02	3.96E-03	3.25E-04	4.09E-05	8.45E-07	1.06E-07	7.25E-04	9.14E-05	2.49E-03	3.14E-04	2.38E-03	3.00E-04
	59†	2.83E-02	3.57E-03	2.93E-04	3.69E-05	7.62E-07	9.60E-08	6.55E-04	8.25E-05	2.25E-03	2.83E-04	2.15E-03	2.71E-04
	73†	2.83E-02	3.57E-03	2.93E-04	3.69E-05	7.62E-07	9.60E-08	6.55E-04	8.25E-05	2.25E-03	2.83E-04	2.15E-03	2.71E-04
	96†	2.56E-02	3.22E-03	2.65E-04	3.33E-05	6.88E-07	8.67E-08	5.91E-04	7.44E-05	2.03E-03	2.56E-04	1.94E-03	2.42E-04

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

† Emission rates include evaporative cooling and steam mass flow augmentation.

Source: ECT, 2001.

Table 2-6. Maximum HAP Pollutant Emission Rates for 100 Percent Load and Three Temperatures—SC CTGs

Unit Load (%)	Ambient Temp. (°F)	1,3-Butadiene		Acetaldehyde		Acrolein		Benzene		Ethylbenzene		Formaldehyde	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	35	1.52E-04	1.91E-05	1.52E-03	1.91E-04	4.76E-05	6.00E-06	1.04E-03	1.31E-04	1.30E-04	1.64E-05	1.30E-09	1.64E-10
	73†	1.37E-04	1.72E-05	1.37E-03	1.72E-04	4.30E-05	5.42E-06	9.38E-04	1.18E-04	1.17E-04	1.48E-05	1.17E-09	1.48E-10
	96†	1.23E-04	1.56E-05	1.23E-03	1.56E-04	3.88E-05	4.89E-06	8.46E-04	1.07E-04	1.06E-04	1.33E-05	1.06E-09	1.33E-10

Unit Load (%)	Ambient Temp. (°F)	Mercury		Naphthalene		PAH		Propylene Oxide		Toluene		Xylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	35	3.14E-02	3.96E-03	3.25E-04	4.09E-05	8.45E-07	1.06E-07	7.25E-04	9.14E-05	2.49E-03	3.14E-04	2.38E-03	3.00E-04
	73†	2.83E-02	3.57E-03	2.93E-04	3.69E-05	7.62E-07	9.60E-08	6.55E-04	8.25E-05	2.25E-03	2.83E-04	2.15E-03	2.71E-04
	96†	2.56E-02	3.22E-03	2.65E-04	3.33E-05	6.88E-07	8.67E-08	5.91E-04	7.44E-05	2.03E-03	2.56E-04	1.94E-03	2.42E-04

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

† Emission rates include evaporative cooling.

Source: ECT, 2001.

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

Pollutant	CTGs	Emergency Diesel Engines	Cooling Tower	MEC Totals
NO_x	386.9	4.4	N/A	391.3
CO	348.0	1.0	N/A	349.0
PM	179.1	0.2	1.6	180.9
PM_{10}	179.1	0.1	1.0	180.2
SO_2	68.7	0.1	N/A	68.8
VOCs	28.6	0.2	N/A	28.8
Lead	0.3	<0.001	N/A	0.3
Mercury	0.000013	<0.00001	N/A	0.000013
H_2SO_4 mist	10.4	<0.001	N/A	10.4
1,3-Butadiene	0.0010	<0.00001	N/A	0.0010
Acetaldehyde	0.7416	<0.00001	N/A	0.7416
Acrolein	0.0964	<0.00001	N/A	0.0964
Benzene	0.3149	<0.00001	N/A	0.3149
Ethylbenzene	0.3923	<0.00001	N/A	0.3923
Formaldehyde	1.9615	<0.00001	N/A	1.9615
Naphthalene	0.0109	<0.00001	N/A	0.0109
Polycyclic Aromatic Hydrocarbons	0.0081	<0.00001	N/A	0.0081
Propylene Oxide	0.4921	<0.00001	N/A	0.4921
Toluene	1.1700	<0.00001	N/A	1.1700
Xylene	1.1201	<0.00001	N/A	1.1201

Note: N/A = not applicable.

Sources: EPMEC, 2001.
ECT, 2001.
General Electric, 2001.

annual basis and were developed to provide conservative estimates of annual emission rates. For the CTG/HRSG unit, two profiles were developed. CC CTG/HRSG Profile A consists of 8,760 hr/yr operation at 73°F ambient air temperature, baseload, with inlet air evaporative cooling and steam mass flow augmentation. CC CTG/HRSG Profile B is comprised of: (a) 540 hr/yr at baseload operation and 35°F ambient air temperature, (b) 1,620 hr/yr at baseload operation and 59°F ambient air temperature with inlet air evaporative cooling and steam mass flow augmentation, (c) 4,764 hr/yr at baseload operation and 73°F ambient air temperature with inlet air evaporative cooling and steam mass flow augmentation, and (d) 1,836 hr/yr at baseload operation and 96°F ambient air temperature with inlet air evaporative cooling and steam mass flow augmentation.

For the SC CTGs, two annual profiles were also developed. SC CTG Profile A consists of 5,000 hr/yr operation at 73°F ambient air temperature, baseload, with inlet air evaporative cooling. SC CTG Profile B consists of: (a) 1,000 hr/yr at baseload operation and 35°F ambient air temperature (representative winter temperature), (b) 3,000 hr/yr at baseload operation and 73°F ambient air temperature (average annual temperature), and (c) 1,000 hr/yr at baseload operation and 96°F ambient air temperature (representative summer typical peak/extreme temperature).

For the CC CTG/HRSG unit, maximum annualized rates are projected to occur under CC CTG/HRSG Profile A operating conditions. For the SC CTGs, maximum annualized rates are projected to occur under SC CTG Profile B operating conditions.

Annual emission rate estimates for the mechanical draft cooling tower, emergency electrical generator and fire water pump diesel-fired engines, and total MEC annual emissions are also shown in Table 2-7. Details of the annualized emission calculations are included in Appendix C. Stack parameters for the natural gas-fired CC CTG/HRSG, SC CTGs, and cooling tower are provided in Tables 2-8, 2-9, and 2-10, respectively.

Table 2-8. Stack Parameters for Three Unit Loads and Four Ambient Temperatures—CC CTG/HRSG

Unit Load (%)	Ambient Temperature (°F)	Stack Height ft	Stack Height meters	Stack Exit Temperature °F	Stack Exit Temperature K	Stack Exit Velocity ft/sec	Stack Exit Velocity m/sec	Stack Diameter ft	Stack Diameter meters
100	35	135	41.1	187	359	61.1	18.6	19.0	5.79
	59†	135	41.1	193	363	62.3	19.0	19.0	5.79
	73†	135	41.1	195	364	60.8	18.5	19.0	5.79
	96†	135	41.1	199	366	58.4	17.8	19.0	5.79
75	35	135	41.1	169	349	46.8	14.3	19.0	5.79
	73	135	41.1	177	354	45.3	13.8	19.0	5.79
	96	135	41.1	182	356	43.8	13.4	19.0	5.79
50	35	135	41.1	154	341	37.5	11.4	19.0	5.79
	73	135	41.1	166	348	37.1	11.3	19.0	5.79
	96	135	41.1	174	352	36.6	11.1	19.0	5.79

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

† Evaporative cooling and steam mass flow augmentation.

Sources: GE, 2001.
ECT, 2001.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—SC CTGs

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	35	135	41.1	1,092	862	146.5	44.7	19.0	5.79
	73†	135	41.1	1,128	882	140.8	42.9	19.0	5.79
	96†	135	41.1	1,146	892	136.2	41.5	19.0	5.79
75	35	135	41.1	1,137	887	118.8	36.1	19.0	5.79
	73	135	41.1	1,165	903	115.3	35.1	19.0	5.79
	96	135	41.1	1,185	914	112.2	34.2	19.0	5.79
50	35	135	41.1	1,185	914	100.7	30.7	19.0	5.79
	73	135	41.1	1,200	922	98.0	29.9	19.0	5.79
	96	135	41.1	1,200	922	95.5	29.1	19.0	5.79

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

† Evaporative cooling.

Sources: GE, 2001.
ECT, 2001.

Table 2-10. Cooling Tower Stack Parameters

	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
	ft	meters	°F	K	ft/sec	m/sec	ft	meters
Cooling Tower (Per Cell)	60	18.3	100	311	26.4	8.1	40.0	12.2

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

Sources: EPMEC, 2001.
ECT, 2001.

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 EPA has enacted primary and secondary NAAQS for six air pollutants (40 Code of Federal Regulations [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 enacted 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 the NAAQS 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 MEC will be located in Manatee County approximately 0.6 miles northeast of Piney Point. Manatee 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 Manatee County, as unclassifiable/attainment with respect to the 1-hour ozone standard.

Manatee 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 ($\mu g/m^3$ unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2 (ppmv) [$\mu g/m^3$]	3-hour[1]		0.5 [1,300]	0.5 [1,300]
	24-hour[1]	0.14 [365]		0.1 [260]
	Annual[2]	0.030 [80]		0.02 [60]
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) [$\mu g/m^3$]	1-hour[1]	35 [40,000]		35 [40,000]
	8-hour[1]	9 [10,000]		9 [10,000]
CO	1-hour[1]			40,000
	8-hour[1]			10,000
Ozone (ppmv) [$\mu g/m^3$]	1-hour[9]	0.12 [235]		0.12 [235]
	8-hour[10,11]	0.08 [157]	0.08 [157]	
NO_2 (ppmv) [$\mu g/m^3$]	Annual[2]	0.053 [100]	0.053 [100]	0.05 [100]
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

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

3.3 PSD NSR APPLICABILITY

The MEC CTGs will each have a heat input greater than 250 million British thermal units per hour (MMBtu/hr), will be located in an attainment area, and will have potential emissions of a regulated pollutant in excess of 100 tpy. Therefore, MEC 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 that are emitted at or above the specified PSD significant emission rate levels.

Comparisons of estimated potential annual emission rates for the MEC 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, 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 MEC are provided in Appendix C.

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

Pollutant	MEC Project Emissions (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	391.3	40	Yes
CO	349.0	100	Yes
PM	180.9	25	Yes
PM_{10}	180.2	15	Yes
SO_2	68.8	40	Yes
Ozone/VOC	28.8	40	No
Lead	0.3	0.6	No
Mercury	0.000013	0.1	No
Total fluorides	<0.001	3	No
H_2SO_4 mist	10.4	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, 2001.

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 that is emitted by the proposed MEC 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 that 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 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 pollutant 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 MEC 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 below the appropriate Rule 62-210.200(259), F.A.C., significant impact level, as presented in Table 4-2. The EPA PSD Class I area significant impact levels are provided in Table 4-3.

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.

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.

Table 4-3. EPA PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Concentration ($\mu g/m^3$)
SO_2	Annual	0.1
	24-Hour	0.2
	3-Hour	1.0
PM_{10}	Annual	0.2
	24-Hour	0.3
NO_2	Annual	0.1
CO	8-Hour	N/A
	1-Hour	N/A
Lead	Quarterly	N/A

Source: EPA, 1998.
ECT, 2001.

In summary, Table 4-1 provides the ambient air impact concentration thresholds that trigger the requirement to conduct preconstruction ambient air quality monitoring; Table 4-2 provides the ambient air impact concentration thresholds that trigger multi-source, interactive dispersion modeling for PSD Class II areas; and Table 4-3 provides the ambient air quality impact concentrations that trigger multi-source, interactive modeling for PSD Class I areas.

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

On October 17, 1988, EPA promulgated PSD increments for NO_2; the effective date of the new regulation was October 17, 1989. However, the baseline date for NO_2 increment consumption was set at 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 that were based on TSP. Baseline dates and areas that were previously established for the original TSP increments remain in effect for the new PM_{10} increments. Revised NAAQS for PM, which 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 4-4.

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

Table 4-4. 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.

source or major modification subject to the requirements of 40 CFR §52.21 or Section 62-212.400, F.A.C. The trigger date is the date after which the minor source baseline date may be established. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

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

- The actual emissions representative of sources in existence on the applicable minor source baseline date.
- The allowable emissions of major stationary sources 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:

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

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment.

The ambient impact analysis for the MEC 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 for those that will cause a small increase in emissions.

The growth analysis generally includes:

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

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

The visibility impairment analysis pertains particularly to Class I area impacts and other areas where good visibility is of special concern. A quantitative estimate of visibility impairment is conducted, if warranted by the scope of the project under review.

The additional impact analyses for the MEC is provided in Sections 9.0 and 10.0.

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 with 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, MEC potential emission rates of NO_x, CO, SO_2, H_2SO_4 mist, 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 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 is applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 MMBtu/hr), based on the lower heating value (LHV) of the fuel fired. 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 emissions criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The MEC 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.

There are no NESHAPS that are applicable to the MEC emission sources. MEC will have potential emissions of HAPs less than the major source thresholds of 10 tpy for any individual HAP and 25 tpy for total HAPs. MEC is, therefore, not subject to the case-by-case MACT requirements of Section 112(g)(2)(B) of the 1990 CAA Amendments.

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 62-296.417, F.A.C., specify emission standards for 17 categories of sources. None of these categories are applicable to CTGs. Rule 62-204.800(7) incorporates the federal NSPS by reference, including Subpart GG.

Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAPs, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the MEC CTGs. 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 Appendix C. BACT emission limitations proposed for MEC 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 its low ash and sulfur content, natural gas combustion generates inherently low PM/PM_{10} emissions.

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.

Source: 40 CFR 60, Subpart 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.

5.3.1 POTENTIAL CONTROL TECHNOLOGIES

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

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

Centrifugal (cyclone) separators are primarily used to recover material from an exhaust stream before the stream is ducted to the principal control device since cyclones are effective in removing only large sized (greater than 10 microns) particles. Particles generated from natural gas 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 post-process technologies would be technically feasible for controlling PM/PM_{10} emissions from CTGs, none of the previously described control equipment has 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 MEC CTGs 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 content. 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 MEC CC CTG/HRSG and SC CTGs 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. MEC will include one 5-cell, fresh water 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 MEC cooling tower will be controlled using high efficiency drift eliminators. The cooling tower will achieve a drift loss rate of no more than 0.0005 percent of the 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 and good combustion practice. Table 5-6 provides RBLC database PM/PM_{10} BACT determinations for cooling towers. A recent final FDEP PM/PM_{10} BACT determination for

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 MS3002G 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. MEADE	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-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
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		6/29/95	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		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
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			Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 2001.
ECT, 2001.

Table 5-6. RBLC PM Summary - Cooling Towers

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate	Emission Limits	Control System Description	Basis
			Issuance	Last Update					
CA-0713	TEXACO REFINING AND MARKETING, INC.	BAKERSFIELD	1/19/96	11/23/96	COOLING TOWER	18 000 GAL PER MIN	30 2 LB/DAY	CELLULAR TYPE DRIFT ELIMINATOR	BACT-OTHER
FL-0050	FLORIDA POWER CORPORATION	CRYSTAL RIVER	8/30/90	5/14/93	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	9/4/92	8/8/94	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	10/1/93	8/31/94	COOLING TOWER (2)		5.9 LB/HR	DRIFT ELIMINATOR	BACT-PSD

Source: RBLC, 2000

cooling towers is the 0.002 percent drift loss rate limit made for the City of Tallahassee Purdom Unit 8. Recent draft FDEP PM/PM_{10} BACT determinations for fresh water cooling towers include a drift loss limit of 0.002 percent (for the Calpine Osprey Energy Center) and 0.0005 percent (for the CPV Gulf Coast Power Generating Facility).

Because post-process stack controls for PM/PM_{10} are not appropriate for CTGs, the use of good combustion practices and clean fuels is considered to be BACT. The MEC CTGs 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 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, 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 MEC CTGs.

5.4 BACT ANALYSIS FOR CO

CO emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting CO emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of CO 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 emissions.

An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in CO emission rates. Emissions of NO_x and CO are inversely related; i.e., decreasing NO_x emissions will result in an increase in CO emissions. Accordingly, combustion turbine vendors have had to consider the competing factors involved in NO_x and CO formation in order to develop units that achieve acceptable emission levels for both pollutants.

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

Emission Source	Proposed PM/PM_{10} BACT Emission Limits
CC CTG/HRSG Unit	10 percent opacity
SC CTGs (Per CTG)	10 percent opacity
Fresh Water Cooling Tower	0.0005 percent drift

Source: ECT, 2001.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO from CTGs: (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 CTGs, approximately 99 percent, CO emissions are inherently low.

Oxidation Catalysts

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of CO to carbon dioxide (CO_2) at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for conventional oxidation catalysts is between 650 and 1,150°F. Recently, high temperature oxidation catalysts have been developed which can tolerate higher temperatures; i.e., greater than 1,200°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature for CO up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant CO oxidation will occur at any temperature above roughly 500°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst that will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time that 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.

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

Oxidation catalysts are nonselective and will oxidize other compounds in addition to CO. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. 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 MEC CTGs. Information regarding energy, environmental, and economic impacts and proposed BACT limits for CO 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 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 fired with natural gas.

Because CO emission rates from CTGs 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. The MEC location (Manatee 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 MEC

CO emissions demonstrates 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 MEC CC CTG/HRSG is projected to have a pressure drop across the catalyst bed of approximately 1.1 inch of water. This pressure drop will result in a 0.22 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 3,372,600 kilowatt-hours (kwh) (11,508 MMBtu) per year at a nominal baseload (175 MW) operation and 100 percent capacity factor. An oxidation catalyst system for the MEC SC CTGs is projected to have a pressure drop across the catalyst bed of approximately 1.3 inches of water. This pressure drop will result in a 0.26 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 4,550,000 kwh (15,525 MMBtu) per year at baseload (175 MW) operation and 57.1 percent capacity factor (i.e., 5,000 hr/yr operation per CTG) for the two SC CTGs. Total energy penalty is equivalent to the use of 25.8 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 three CTGs. The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $237,678 per year for all three CTGs.

5.4.3 ECONOMIC IMPACTS

Economic evaluations of oxidation catalyst systems were performed using the OAQPS factors previously summarized in Table 5-1 and project-specific economic factors provided in Table 5-8. Specific CC CTG/HRSG capital and annual operating costs for a conventional oxidation catalyst control system are summarized in Tables 5-9 and 5-10. Specific SC CTG capital and annual operating costs for a high temperature oxidation catalyst control system are summarized in Tables 5-11 and 5-12.

The base case MEC annual CO exhaust concentration and emission rate are 11.7 ppmvd corrected to 15-percent O_2 and 206.0 tpy, respectively, for the CC CTG/HRSG based on CC

CTG/HRSG baseload operation for 8,760 hr/yr at 73°F with evaporative cooling and steam mass flow augmentation; i.e., CC CTG/HRSG Annual Profile A. The CC CTG/HRSG oxidation catalyst controlled annual CO exhaust concentration and emission rate, based on 90.0 percent control efficiency, are 1.2 ppmvd corrected to 15-percent O_2 and 20.6 tpy, respectively. Base case and controlled CC CTG/HRSG CO emission rates are summarized in Table 5-13.

The base case MEC annual CO exhaust concentration and emission rate are 7.4 ppmvd corrected to 15-percent O_2 and 142.0 tpy, respectively, for the two SC CTGs based on SC CTG baseload operation for: (a) 1,000 hr/yr at baseload operation and 35°F ambient air temperature (representative winter temperature), (b) 3,000 hr/yr at baseload operation and 73°F ambient air temperature (average annual temperature), and (c) 1,000 hr/yr at baseload operation and 96°F ambient air temperature (representative summer temperature); i.e., SC CTG Annual Profile B. The SC CTG oxidation catalyst controlled annual CO exhaust concentration and emission rate, based on 90.0 percent control efficiency, are 0.7 ppmvd corrected to 15 percent O_2 and 14.2 tpy, respectively. Base case and controlled SC CTG CO emission rates are summarized in Table 5-13.

The cost effectiveness of oxidation catalyst for CC CTG/HRSG CO emissions was determined to be $2,475 per ton of CO removed. The cost effectiveness of oxidation catalyst for the SC CTG CO emissions was determined to be $8,981 per ton of CO removed. The cost effectiveness of oxidation catalyst control technology was significantly higher for the SC CTG compared to the CC CTG/HRSG due to the lower annual operating hours (5,000 vs. 8,760 hr/yr) and higher purchased equipment cost of the high temperature oxidation catalyst ($1,274,130 per SC CTG vs. $850,630 for the CC CTG/HRSG). Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible for either the CC CTG/HRSG unit or the SC CTGs. The cost effectiveness of CO oxidation catalyst control systems for the MEC CC CTG/HRSG and SC CTGs exceed the cost effectiveness considered unreasonable in recent FDEP BACT determinations for similar facilities; e.g., Gulf Power Smith Unit 3 in July 2000, Calpine Osprey Project in May 2000, and Hardee Power Station Unit 2B in October 1999. The California San Joaquin Valley Unified Air Pollution Control District's BACT policy considers CO

Table 5-8. Economic Cost Factors

Factor	Units	Value
Interest rate	%	7.0
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	0.030
Labor costs (base rates)	$/hour	
Operator		22.00
Maintenance		22.00

*Control system vendor guarantee.

Sources: EPMEC, 2001.
ECT, 2001.

Table 5-9. Capital Costs for Oxidation Catalyst System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	703,000	A
Sales tax	42,180	0.06 x A
Instrumentation	70,300	0.10 x A
Freight	35,150	0.05 x A
Subtotal Purchased Equipment	**850,630**	**B**
Installation		
Foundations and supports	68,050	0.08 x B
Handling and erection	119,088	0.14 x B
Electrical	34,025	0.04 x B
Piping	17,013	0.02 x B
Insulation for ductwork	8,506	0.01 x B
Painting	8,506	0.01 x B
Subtotal Installation Cost	**255,189**	
Total Direct Costs (TDC)	**1,105,819**	
Indirect Costs		
Engineering	85,063	0.10 x B
Construction and field expenses	42,532	0.05 x B
Contractor fees	85,063	0.10 x B
Startup	17,013	0.02 x B
Performance test	8,506	0.01 x B
Contingency	25,519	0.03 x B
Total Indirect Costs (TIC)	**263,695**	
TOTAL CAPITAL INVESTMENT (TCI)	**1,369,514**	TDC + TIC

Source: ECT, 2001.

Table 5-10. Annual Operating Costs for Oxidation Catalyst System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	693,696	3-yr replacement
Credit for Recycled Catalyst	(93,600)	15%
Annualized Catalyst Costs	**228,669**	
Energy Penalties		
Turbine backpressure	101,178	0.22% penalty
Total Direct Costs (TDC)	**329,846**	
Indirect Costs		
Administrative charges	27,390	0.02 x TCI
Property taxes	13,695	0.01 x TCI
Insurance	13,695	0.01 x TCI
Capital recovery	74,201	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**128,982**	
TOTAL ANNUAL COST (TAC)	**485,927**	TDC + TIC

Sources: ECT, 2001.

Table 5-11. Capital Costs for Oxidation Catalyst System, Two SC CTGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	2,106,000	A
Sales tax	126,360	0.06 x A
Instrumentation	210,600	0.10 x A
Freight	105,300	0.05 x A
Subtotal Purchased Equipment	**2,548,260**	**B**
Installation		
Foundations and supports	203,861	0.08 x B
Handling and erection	356,756	0.14 x B
Electrical	101,930	0.04 x B
Piping	50,965	0.02 x B
Insulation for ductwork	25,483	0.01 x B
Painting	25,483	0.01 x B
Subtotal Installation Cost	**764,478**	
Total Direct Costs (TDC)	**3,312,738**	
Indirect Costs		
Engineering	254,826	0.10 x B
Construction and field expenses	127,413	0.05 x B
Contractor fees	254,826	0.10 x B
Startup	50,965	0.02 x B
Performance test	25,483	0.01 x B
Contingency	76,448	0.03 x B
Total Indirect Costs (TIC)	**789,961**	
TOTAL CAPITAL INVESTMENT (TCI)	**4,102,699**	TDC + TIC

Source: ECT, 2001.

Table 5-12. Annual Operating Costs for Oxidation Catalyst System, Two SC CTGs

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Catalyst costs		
. Replacement (materials and labor)	1,804,752	3-yr replacement
Credit for Recycled Catalyst	(243,600)	15%
Annualized Catalyst Costs	**594,880**	
Energy Penalties		
Turbine backpressure	136,500	0.26% penalty
Total Direct Costs (TDC)	**731,380**	
<u>Indirect Costs</u>		
Administrative charges	82,054	0.02 x TCI
Property taxes	41,027	0.01 x TCI
Insurance	41,027	0.01 x TCI
Capital recovery	252,302	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**416,410**	
TOTAL ANNUAL COST (TAC)	**1,147,790**	TDC + TIC

Sources: ECT, 2001

Table 5-13. Summary of CO BACT Analysis

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Rates (tpy)	Total Reduction (tpy)	Economic Impacts: Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)	Energy Impacts: Increase Over Baseline (MMBtu/yr)	Environmental Impacts: Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
A. CC CTG/HRSG										
Oxidation Catalyst	4.7	20.6	185.4	1,369,514	458,827	2,475	N/A	11,508	N	Y
	[1.2 ppmvd at 15% O_2]									
Base Case	47.0	206.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	[11.7 ppmvd at 15% O_2]									
B. SC CTGs										
Oxidation Catalyst	5.7	14.2	127.8	4,102,699	1,147,790	8,981	N/A	15,525	N	Y
	[0.7 ppmvd at 15% O_2]									
Base Case	56.8	142.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	[7.4 ppmvd at 15% O_2]									

Basis: One, GE 7FA CC CTG/HRSG.
Two, GE 7FA SC CTGs.

Sources: Coastal, 2001.
ECT, 2001.
GE, 2001.

Y:\ODP-01\ELPASO\MEC\H-513.xls\Table 5-13--030501 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 5-13.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

The use of oxidation catalyst to control CO from CTGs is typically required only for facilities located in CO nonattainment areas. BACT CO limits obtained from the RBLC database for natural gas-fired CTGs are provided in Table 5-14. A summary of recent FDEP CO BACT determinations for natural gas-fired CTGs is provided in Table 5-15.

As noted above in Section 5.4.3, use of oxidation catalyst technology to control CO emissions is not considered to be economically feasible for either the CC CTG/HRSG unit or the SC CTGs based on high control costs.

In addition, 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 fired with natural gas. Because CO emission rates from CTGs 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. These control techniques have been considered by FDEP to represent BACT for CO for recent CTG projects; e.g., the 2000 Department determinations for the Calpine Osprey Project and 2001 determination for the Tampa Electric Company Bayside Project.

At baseload operation and 73°F ambient temperature, the CC CTG/HRSG CO exhaust concentration is projected to be 7.4 ppmvd at 15 percent O_2. At baseload operation, 59°F ambient temperature, with evaporative cooling and steam mass flow augmentation, the CC CTG/HRSG CO exhaust concentration is projected to be 11.8 ppmvd at 15 percent

Table 5-14. 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 I	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-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	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-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-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	5/31/98	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-0062	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-0062	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-0063	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	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/98	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC. CLEAN BURNING FUELS	BACT-PSD
GA-0083	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-0089	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-0016	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	11/30/89	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	35989	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 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
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 5-14. 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	650 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUSI	8/12/92	4/6/95	TURBINE (NATURAL GAS) (3)	6500 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-0238	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 5-15. Florida BACT CO Summary—Natural Gas-Fired CTs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
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
9/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/4/98	Santa Rosa Energy, LLC (DB Off)	167	9	Good combustion
12/4/98	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
10/8/99	TECO Power Services – Hardee Power Station	75	25	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
Draft	CPV Gulfcoast, Ltd. (Power Augmentation Off)	170	9	Good combustion
Draft	CPV Gulfcoast, Ltd. (Power Augmentation On)	170	15	Good combustion

Source: FDEP, 2001.
ECT, 2001.

O_2. At baseload operation, 73°F ambient temperature, with evaporative cool ing, the SC CTG CO exhaust concentration is projected to be 7.4 ppmvd at 15 percent O_2. At 50 percent load, 96°F ambient temperature, the SC CC CTG CO exhaust concentration is projected to be 8.0 ppmvd at 15 percent O_2. Table 5-16 summarizes the CO BACT emission limits proposed for the MEC CC CTG/HRSG unit and the SC CTGs.

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 fuel bound nitrogen (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.

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

Table 5-16. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits	
	ppmvd at 15 percent O_2†	lb/hr*
GE 7FA - CC CTG/HRSG		
A. All Loads Without Steam Mass Flow Augmentation		
CO	8.0	31.0
B. All Loads With Steam Mass Flow Augmentation		
CO	12.0	48.4
GE 7FA - SC CTGs (Per SC CTG)		
A. All Loads		
CO	8.0	31.0

†24-hour block average.
*3-hour test average.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

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, with standard combustors.
- 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

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

The use of water or steam injection in standard combustors 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 temperatures are the same, causing a decrease in thermal NO_x emissions in comparison to a conventional diffusion burner. A typical DLN combustor incorporates fuel staging using several operating modes as follows:

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

As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.

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

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. For CTGs capable of 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 MEC are GE 7FA units. The XONON™ Cool Combustion technology is not yet commercially available for these units. 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 MEC 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:

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

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

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

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), 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.

SCONO$_x$™

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:

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

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

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

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:

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

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 carbon dioxide. The regeneration gas is diluted to under 4-percent hydrogen using steam as a carrier gas; the typical system is designed for 2% hydrogen. The regeneration gas reaction is:

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

For installations above 450°F, the $SCONO_x$™ 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:

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

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. APP 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:

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

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

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

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

(below 500°F)

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

(above 500°F)

A programmable logic controller (PLC) 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 32 MW that have demonstrated successful application of the $SCONO_x$™ control technology.

Technical Feasibility

With the exception of the XONON™ Cool Combustion technology, all of the combustion process modification technologies mentioned (water or steam injection and DLN combustor design) would be feasible for the MEC CC CTG/HRSG unit and SC CTGs. As noted previously, the XONON™ Cool Combustion technology is not yet commercially available for the GE "F" Class 7FA CTGs. 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 not technically feasible for the MEC SC CTGs because the temperature required for this technology (between 300 and 700°F) is well below the 1,100°F typically occurring for the GE F-class SC CTG.

The SCONO$_x$™ control technology is considered technically feasible for the CC CTG/HRSG unit 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 GE 7FA CTG planned for the MEC CC CTG\HRSG unit has a nominal generation capacity of 175 MW. Accordingly, the MEC CC CTG is 35 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 MEC CC CTG/HRSG was confined to advanced DLN combustors and the application of postcombustion conventional SCR and SCONO$_x$™ control technologies. The BACT analysis for NO_x for the MEC SC CTGs was confined to advanced DLN combustors and the application of postcombustion high temperature SCR control technology. 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.

For the MEC CC CTG/HRSG unit, the installation of conventional 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 MEC CC CTG/HRSG is projected to have a pressure drop across the catalyst bed of approximately 1.5 inches of water. This pressure drop will result in a 0.3-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 4,599,000 kwh (15,692 MMBtu) per year at a nominal baseload (175 MW) and 8,760 hr/yr operations. This energy penalty is equivalent to the use of 14.95 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 $0.030/kwh, is $138,000 per year.

For the MEC SC CTGs, the installation of high temperature SCR technology will also cause an increase in back pressure on the CTGs due to the pressure drop across the catalyst bed. A high temperature SCR control system for the MEC SC CTGs is projected to have a pressure drop across the catalyst bed of approximately 4.5 inches of water. This pressure drop will result in a 0.9-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 7,875,000 kwh (26,871 MMBtu) per year at baseload (175 MW) and 5,000 hr/yr operations per CTG and 15,750,000 kwh (53,741 MMBtu) per year for the two SC CTGs. This energy penalty is equivalent to the use of 51.2 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 $0.030/kwh, is $472,500 per year for both SC CTGs.

The installation of $SCONO_x$™ technology on the MEC CC CTG/HRSG unit 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 MEC CC CTG/HRSG 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 15,330,000 kwh (52,308 MMBtu) per year at baseload (175 MW) and 8,760 hr/yr operations. This energy penalty is equivalent to the use of 49.82 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 $0.030/kwh, is $459,900 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 conventional SCR (CC CTG/HRSG), high temperature SCR (SC CTGs), and $SCONO_x$™ (CC CTG/HRSG) controls. The base case MEC annual NO_x exhaust concentration and emission rate are 12.1 ppmvd corrected to 15 percent O_2 and 348.7 tpy, respectively, for the CC CTG/HRSG based on CC CTG/HRSG baseload operation for 8,760 hr/yr at 73°F with evaporative cooling and steam mass flow augmentation; i.e., CC CTG/HRSG Annual Profile A. The CC CTG/HRSG SCR controlled annual NO_x exhaust concentration and emission rate, based on a 71.1 percent control efficiency, are 3.5 ppmvd corrected to 15-percent O_2 and 100.9 tpy, respectively. The CC CTG/HRSG $SCONO_x$™ controlled annual NO_x exhaust concentration and emission rate, based on a 83.5 percent control efficiency, are 2.0 ppmvd corrected to 15 percent O_2 and 57.6 tpy, respectively.

The base case MEC annual NO_x exhaust concentration and emission rate are 9.0 ppmvd corrected to 15-percent O_2 and 286.0 tpy, respectively, for the two SC CTGs based on SC CTG baseload operation for: (a) 1,000 hr/yr at baseload operation and 35°F ambient air temperature (representative winter temperature), (b) 3,000 hr/yr at baseload operation and 73°F ambient air temperature (average annual temperature), and (c) 1,000 hr/yr at baseload operation and 96°F ambient air temperature (representative summer temperature); i.e., SC CTG Annual Profile B. The SC CTG high temperature SCR controlled annual NO_x exhaust concentration and emission rate, based on a 61.1 percent control efficiency, are 3.5 ppmvd corrected to 15-percent O_2 and 111.2 tpy, respectively. Base case and controlled NO_x emission rates are summarized in Table 5-20.

The cost impact analyses were conducted using the OAQPS factors previously summarized in Table 5-1 and MEC specific economic factors provided in Table 5-8. Tables 5-17 and 5-18 summarize specific capital and annual operating costs for the CC CTG/HRSG conventional SCR control system, respectively. Tables 5-19 and 5-20 summarize specific capital and annual operating costs for the CC CTG/HTRSG $SCONO_x$™ control system, respectively, based on Alstom data and a Department of Energy (DOE) study (DOE, 1999). Tables 5-21 and 5-22 summarize specific capital and annual operating costs for the SC CTG high temperature SCR control system, respectively.

Average cost effectiveness for the application of conventional SCR and $SCONO_x$™ technology to the MEC CC CTG/HRSG was determined to be $3,535 and $24,187 per ton of NO_x removed, respectively. Incremental cost effectiveness of $SCONO_x$™ technology was determined to be $142,512 per ton of NO_x removed. Average cost effectiveness for the application of high temperature SCR technology to the MEC SC CTGs was determined to be $22,052 per ton of NO_x removed. The CC CTG/HRSG control cost for conventional SCR is considered economically reasonable. However, the incremental control cost for $SCONO_x$™ (CC CTG/HRSG) and high temperature SCR (SC CTGs) are substantially higher than previously considered reasonable by the FDEP. Tables 5-23 and 5-24 summarize the results of the NO_x BACT analyses for the CC CTG/HRSG and SC CTGs, respectively.

Table 5-17. Capital Costs for Conventional SCR Control System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Purchased equipment	1,150,000	A
Sales tax	69,000	0.06 x A
Instrumentation	115,000	0.10 x A
Freight	57,500	0.05 x A
HRSG Modifications	185,000	
Subtotal Purchased Equipment	**1,576,500**	B
Installation		
Foundations and supports	126,120	0.08 x B
Handling and erection	220,710	0.14 x B
Electrical	63,060	0.04 x B
Piping	31,530	0.02 x B
Insulation for ductwork	15,765	0.01 x B
Painting	15,765	0.01 x B
Subtotal Installation Cost	**472,950**	
Total Direct Costs (TDC)	**2,049,450**	
<u>Indirect Costs</u>		
Engineering	157,650	0.10 x B
Construction and field expenses	78,825	0.05 x B
Contractor fees	157,650	0.10 x B
Startup	31,530	0.02 x B
Performance test	15,765	0.01 x B
Contingency	47,295	0.03 x B
Total Indirect Costs (TIC)	**488,715**	
TOTAL CAPITAL INVESTMENT (TCI)	**2,538,165**	TDC + TIC

Source: ECT, 2001

Table 5-18. Annual Operating Costs for SCR Control System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
Direct Costs		
Operator & Supervisor Labor	13,800	
Maintenance Labor and Material	24,600	
Subtotal Labor and Maintenance Costs	**37,800**	C
Catalyst costs		
Replacement (materials, labor, and disposal)	793,700	
Annualized Catalyst Costs	**302,400**	3-yr replacement
Aqueous ammonia costs	59,200	113/ton
Electricity costs	18,900	
Energy Penalties		
Turbine backpressure	138,000	0.3% penalty
Emission fee credit	(6,197)	$25/ton
Total Direct Costs (TDC)	**550,103**	
Indirect Costs		
Overhead	22,700	0.60 x C
Administrative charges	50,800	0.02 x TCI
Property taxes	25,400	0.01 x TCI
Insurance	25,400	0.01 x TCI
Capital recovery	201,800	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**376,100**	
TOTAL ANNUAL COST (TAC)	**876,203**	TDC + TIC

Sources: EPMEC, 2001.
ECT, 2001.

Table 5-19. Capital Costs for $SCONO_x$™ System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment (lease arrangement)	6,600,000	A
Sales tax	396,000	0.06 x A
Instrumentation	0	Included
Freight	330,000	0.05 x A
HRSG Modifications	185,000	
Subtotal Purchased Equipment	**7,511,000**	B
Installation		
Foundations and supports	600,880	0.08 x B
Handling and erection	1,051,540	0.14 x B
Electrical	300,440	0.04 x B
Piping	150,220	0.02 x B
Insulation for ductwork	75,110	0.01 x B
Painting	75,110	0.01 x B
Subtotal Installation Cost	**2,253,300**	
Total Direct Costs (TDC)	**9,764,300**	
Indirect Costs		
Engineering	751,100	0.10 x B
Construction and field expenses	375,550	0.05 x B
Contractor fees	751,100	0.10 x B
Startup	150,220	0.02 x B
Performance test	75,110	0.01 x B
Contingency	225,330	0.03 x B
Total Indirect Costs (TIC)	**2,328,410**	
TOTAL CAPITAL INVESTMENT (TCI)	**12,092,710**	TDC + TCI

Source: ECT, 2001

Table 5-20. Annual Operating Costs for $SCONO_x$™ Control System, CC CTG/HRSG

Item	Dollars	OAQPS Factor
Direct Costs		
Operator & Supervisor	13,800	
Maintenance Labor and Material	24,000	
Subtotal Labor and Maintenance Costs	**37,800**	C
Catalyst costs		
Annualized Catalyst Costs	**3,750,000**	Alstom lease
Natural gas costs (H_2 reforming)	83,273	
Electricity costs	27,594	
Steam costs (H_2 carrier)	855,414	
Energy Penalties		
Turbine backpressure	459,900	1.0 % penalty
Emission fee credit	(7,277)	$25/ton
Total Direct Costs (TDC)	**5,206,703**	
Indirect Costs		
Overhead	22,700	0.60 x C
Administrative charges	241,900	0.02 x TCI
Property taxes	120,900	0.01 x TCI
Insurance	120,900	0.01 x TCI
Capital recovery	1,327,700	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**1,834,100**	
TOTAL ANNUAL COST (TAC)	**7,040,803**	TDC + TIC

Sources: EPMEC, 2001.
ECT, 2001.

Table 5-21. Capital Costs for High Temperature SCR Control System, Two SC CTGs

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	6,154,000	A
Sales tax	369,200	0.06 x A
Instrumentation	615,400	0.10 x A
Freight	307,700	0.05 x A
Duct Modifications	370,000	
Subtotal Purchased Equipment	**7,816,300**	B
Installation		
Foundations and supports	625,300	0.08 x B
Handling and erection	1,094,300	0.14 x B
Electrical	312,700	0.04 x B
Piping	156,300	0.02 x B
Insulation for ductwork	78,200	0.01 x B
Painting	78,200	0.01 x B
Subtotal Installation Cost	**2,345,000**	
Total Direct Costs (TDC)	**10,161,300**	
Indirect Costs		
Engineering	781,600	0.10 x B
Construction and field expenses	390,800	0.05 x B
Contractor fees	781,600	0.10 x B
Startup	156,300	0.02 x B
Performance test	78,200	0.01 x B
Contingency	234,500	0.03 x B
Total Indirect Costs (TIC)	**2,423,000**	
TOTAL CAPITAL INVESTMENT (TCI)	**12,584,300**	TDC + TIC

Source: ECT, 2001.

Table 5-22. Annual Operating Costs for High Temperature SCR Control System
Two SC CTGs

Item	Dollars	OAQPS Factor
<u>Direct Costs</u>		
Operator & Supervisor Labor	27,700	
Maintenance Labor and Material	48,200	
Subtotal Labor and Maintenance Costs	**75,900**	C
Catalyst costs		
Replacement (materials, labor, and disposal)	4,890,800	
Annualized Catalyst Costs	**1,863,600**	3-yr replacement
Aqueous ammonia costs	23,800	113/ton
Electricity costs	8,600	
Energy Penalties		
Turbine backpressure	472,500	0.9% penalty
Emission fee credit	(4,400)	$25/ton
Total Direct Costs (TDC)	**2,440,000**	
<u>Indirect Costs</u>		
Overhead	45,500	0.60 x C
Administrative charges	251,700	0.02 x TCI
Property taxes	125,800	0.01 x TCI
Insurance	125,800	0.01 x TCI
Capital recovery	865,300	15 yrs @ 7.0%
Total Indirect Costs (TIC)	**1,414,100**	
TOTAL ANNUAL COST (TAC)	**3,854,100**	TDC + TIC

Sources: EPMEC, 2001.
ECT, 2001.

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 5-25. Recent Florida BACT determinations for natural gas-fired CTGs are shown in Table 5-26.

Under all operating scenarios, the maximum NO_x exhaust concentration and hourly mass emission rate from the CC CTG/HRSG unit will be 3.5 ppmvd and 23.8 lb/hr, respectively, based on the application of DLN combustors and conventional SCR. Under all operating scenarios, the maximum NO_x exhaust concentration and hourly mass emission rate from the SC CTGs will be 9.0 ppmvd and 61.0 lb/hr, respectively, based on the application of DLN combustors. Table 5-27 summarizes the NO_x BACT emission limits proposed for MEC. NO_x emission rates proposed as BACT for the MEC CTGs 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 fuels to reduce their sulfur contents prior to delivery to end fuel users. For wellhead natural gas 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 is 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

Table 5-23. Summary of NO_x BACT Analysis - CC CTG/HRSG Unit

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Total 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	13.2 [2.0 ppmvd at 15% O_2]	57.6	291.1	12,092,710	7,040,803	24,187	142,512	52,308	N	N
SCR	23.0 [3.5 ppmvd at 15% O_2]	100.9	247.8	2,538,165	876,203	3,535	N/A	15,692	N	N
Base Case	79.6 [12.1 ppmvd at 15% O_2]	348.7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One, GE 7FA CC CTG/HRSG unit.

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Sources: Coastal, 2001.
ECT, 2001.
GE, 2001.
ABB Alstom, 2001.

Table 5-24. Summary of NO_x BACT Analysis - SC CTGs

Control Option	Emission Impacts: Emission Rates (lb/hr)	Emission Impacts: Emission Rates (tpy)	Emission Impacts: Total 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)
SCR	44.5 [3.5 ppmvd at 15% O_2]	111.2	174.8	12,584,300	3,854,100	22,052	N/A	53,741	N	N
Base Case	114.4 [9.0 ppmvd at 15% O_2]	286.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: Two, GE 7FA SC CTGs.

Sources: Coastal, 2001.
ECT, 2001.
GE, 2001.

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Table 5-25 RBLC NO_x Summary for Natural Gas Fired CTGs (Page 1 of 3)

RBLC ID	Facility Name	City	Permit Dates		Process Description	Thruput Rate		Emission Limit	Control System Description	Basis
			Issuance	Update						
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 0095	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	6/18/90	TURBINE, GAS COGENERATION	457 8	MMBTU/H	0 0135 LB/MMBTU	SCR, STEAM INJECTION	BACT-PSD
CA-0335	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	10/6/94	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	8/5/99	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	6/30/89	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 S1	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	16 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

Table 5-25 RBLC NO_x Summary for Natural Gas Fired CTGs (Page 2 of 3)

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	13.6 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	21.8 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	4/17/98	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	3/26/98	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-PSD
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 OTHER
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	6/25/90	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 REACTI	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 CC	BACT OTHER
ME-0020	CASCO BAY 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	5/8/95	2/2/99	TURBINE, GM LM500	88.6 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	376.0 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 E/	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	3/8/89	5/18/90	TURBINE, LM6000	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)	1,698.0 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	5/31/96	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 5-25. RBLC NO, 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 POWE	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 (ISCR)	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 5-26. Florida BACT NO_x 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	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.
ECT, 2001.

Table 5-27. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits lb/hr*	ppmvd at 15 percent O_2†
CC CTG/HRSG Unit	23.8	3.5
SC CTGs (Per SC CTG)	61.0	9.0

*3-hour test average.
†24-hour block average.

Sources: EPMEC, 2001.
ECT, 2001.

generate wastewater and wet sludge streams requiring treatment and disposal. In a dry FGD system, an alkaline slurry is injected into the combustion process exhaust stream.

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

Technical Feasibility

Treatment of natural gas 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 sulfur content has 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 MEC CTGs 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 MEC CTGs. Pipeline quality natural gas used at the MEC 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 5-28 summarizes the SO_2 and H_2SO_4 mist BACT emission limits proposed for the MEC.

Table 5-28. 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)
CC and SC CTGs		
	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: EPMEC, 2001.
ECT, 2001.

5.7 SUMMARY OF PROPOSED BACT EMISSION LIMITS

Table 5-29 summarizes control technologies proposed as BACT for each pollutant subject to review. Table 5-30 summarizes specific proposed BACT emission limits for each pollutant.

Table 5-29. Summary of BACT Control Technologies

Pollutant	Means of Control
CC and SC CTGs	
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 technology and conventional SCR – CC CTG/HRSG • Use of advanced dry low-NO_x combustor technology – SC CTGs
SO_2/H_2SO_4 mist	• Exclusive use of low-sulfur natural gas.
Cooling Tower	
PM/PM_{10}	• Efficient drift elimination.

Source: ECT, 2001.

Table 5-30. Summary of Proposed BACT Emission Limitations

Pollutant	Proposed BACT Emission Limits (ppmvd @ 15% O_2)*	(lb/hr) †
GE 7FA CC and SC CTGs		
A. All Operating Scenarios		
NO_X (CC CTG/HRSG)	3.5	23.8
NO_X (SC CTGs, Per SC CTG)	9.0	61.0
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. All Loads Without Steam Mass Flow Augmentation (CC CTG/HRSG)		
CO	8.0	31.0
C. All Loads With Steam Mass Flow Augmentation (CC CTG/HRSG)		
CO	12.0	48.4
D. All Loads (SC CTGs, Per SC CTG)		
CO	8.0	31.0
Cooling Tower		
PM/PM_{10}	0.0005 percent drift loss rate	

*24-hour block average.
†3-hour test average.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

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, MEC will have potential emissions of 391.3 tpy NO_x, 349.0 tpy of CO, 180.9 tpy of PM, 180.2 tpy of PM_{10}, 68.8 tpy of SO_2, 28.8 tpy of VOCs, 0.3 tpy of lead, 10.4 tpy of H_2SO_4 mist, and 0.000013 tpy of mercury. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the MEC and the PSD significant emission rate thresholds. As shown in that table, potential emissions of NO_x, CO, PM/PM_{10}, SO_2, 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.

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 MEC 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 scenario evaluated. Thirty-six wind directions were assigned at 10° 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 CC CTG/HRSG and SC CTG operating scenarios (i.e., to determine which 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 MEC CC CTG/HRSG and SC CTG 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, and steam mass flow augmentation). 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 7-3. 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.

Current land use obtained from the Florida Geographic Data Library (FGDL) for the area was 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 MEC is largely agricultural or undeveloped. Based on this land use, the area within a 3-km radius would be characterized as rural using the Auer classification method. A graphical representation of the Auer classification method is provided in Figure 6-1. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

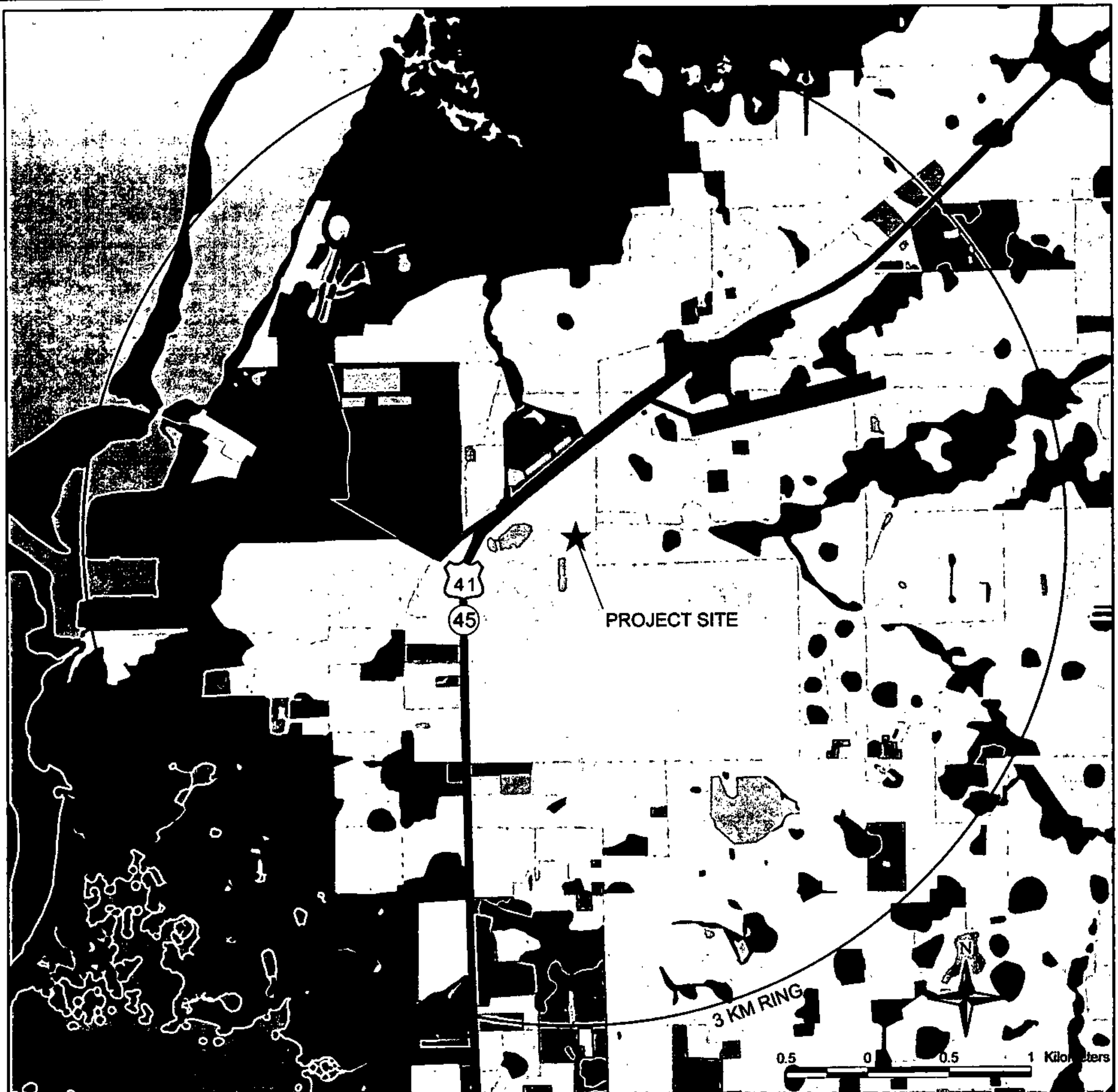
6.5 TERRAIN CONSIDERATION

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*.

The latest available USGS 7.5-minute series topographic maps were examined for terrain features in the vicinity of the MEC (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 cooling tower, CC CTG/HRSG and SC CTG stack bases 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:



LEGEND

URBAN

- RESIDENTIAL, HIGH DENSITY
- COMMERCIAL & SERVICES
- INDUSTRIAL
- INSITUTIONAL
- TRANSPORTATION
- UTILITIES AND COMMUNICATIONS

RURAL

- RESIDENTIAL, LOW DENSITY
- RESIDENTIAL, MEDIUM DENSITY
- WATER
- WETLANDS
- SAND OTHER THAN BEACHES
- BARREN LAND
- DISTURBED LAND
- EXTRACTIVE
- RECREATIONAL
- OPEN LAND
- CROPLAND & PASTURELAND
- TREE CROPS
- FEEDING OPERATIONS
- NURSERIES & VINEYARDS
- SPECIALTY FARMS
- HERBACEOUS
- SHRUB & BRUSHLAND
- MIXED RANGELAND
- UPLAND FOREST
- TREE PLANTATIONS

FIGURE 6-1.
SURROUNDING LAND USE

Sources: Florida Geographic Data Library, 1998; ECT, 2001.

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$$Hg = H + 1.5\ L$$

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 MEC CC CTG/HRSGs, SC CTG's, and cooling tower (135, 135 and 60 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 MEC downwash structures is shown on Figure 6-2. BPIP output consists of 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 <u>RECEPTOR GRIDS</u>

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."

Table 6-1. Building/Structure Dimensions

Facility	Elevation* (ft)	Length (ft)	Width (ft)
Inlet air filters	55	53	53
SC CTG stacks	135	19†	
CC CTG/HRSG stack	135	19†	N/A
HRSG	100	75	53
Demineralizer tank	40	50†	N/A
Raw water tank	40	60†	N/A
Cooling tower	50	250	50
Cooling tower stacks	60	40†	N/A

*Above ground surface.
†Diameter.

Source: EPMEC, 2001.

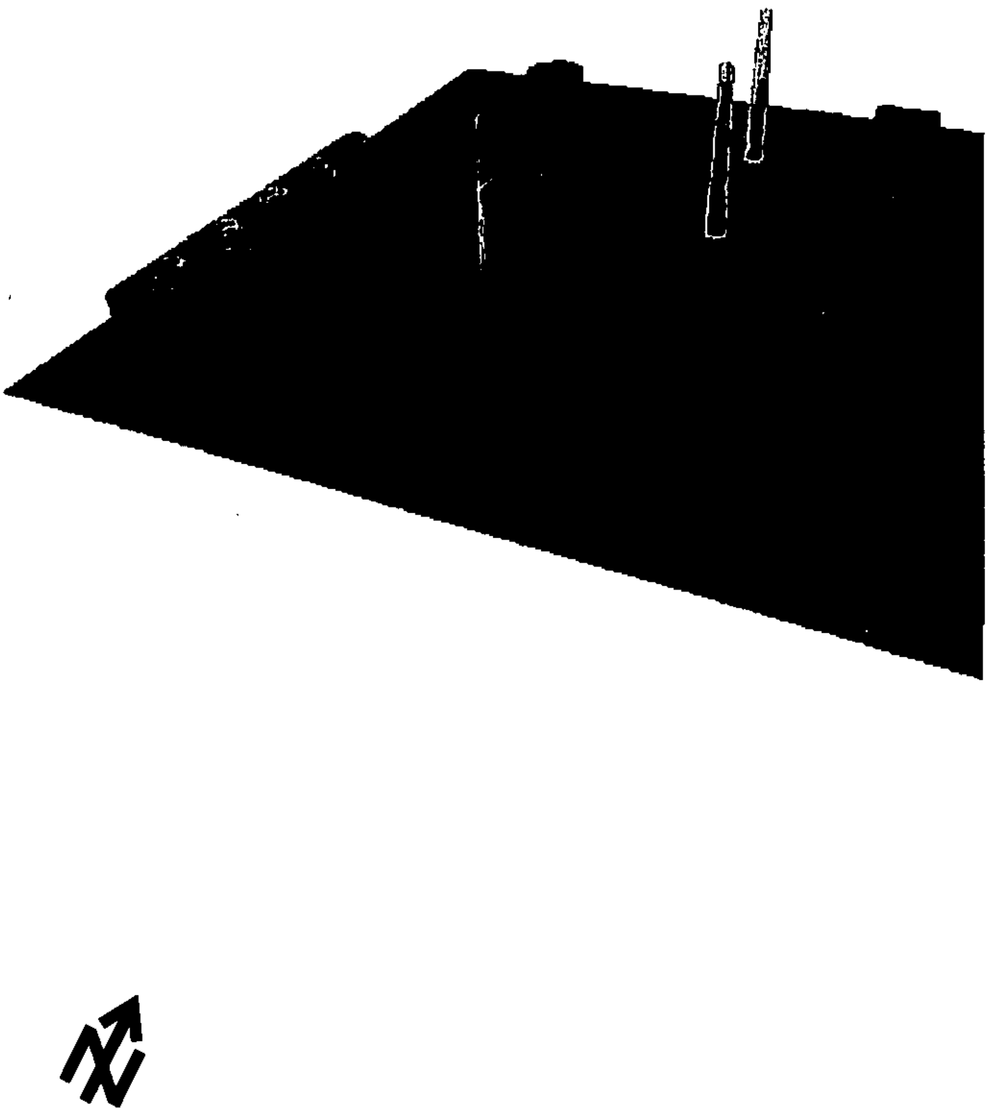

FIGURE 6-2.
DOWNWASH SCHEMATIC

Source: ECT, 2001.

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Section 2.0 provides 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 Receptors: Receptors placed on the site fence line spaced 50 meters apart.
- Near-Field Cartesian Receptors: Receptors starting 100 meters from the site fence lines and extending 1 km at 100-meter spacings.
- Polar Receptor rings (with 36 receptors per ring at 10° intervals) starting 1 km from the site and extending to 2 km at 100-meter spacings.
- Polar Receptor rings (with 36 receptors per ring at 10° intervals) starting 2 km from the site and extending to 4 km at 250-km spacings.
- Polar receptor rings (with 36 receptors per ring at 10° intervals) starting 4 km from the site and extending to 10 km at 500-meter spacings.

To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°.

Figure 6-3 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 6-4.

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 Manatee County, FDEP recommends use of Tampa surface and upper air meteorological data in conducting the air quality analyses. The most recent 5 years of Tampa station (Tampa International Airport—Station No. 12842) surface and upper air meteorological data available from EPA's Support Center for Regulatory Air

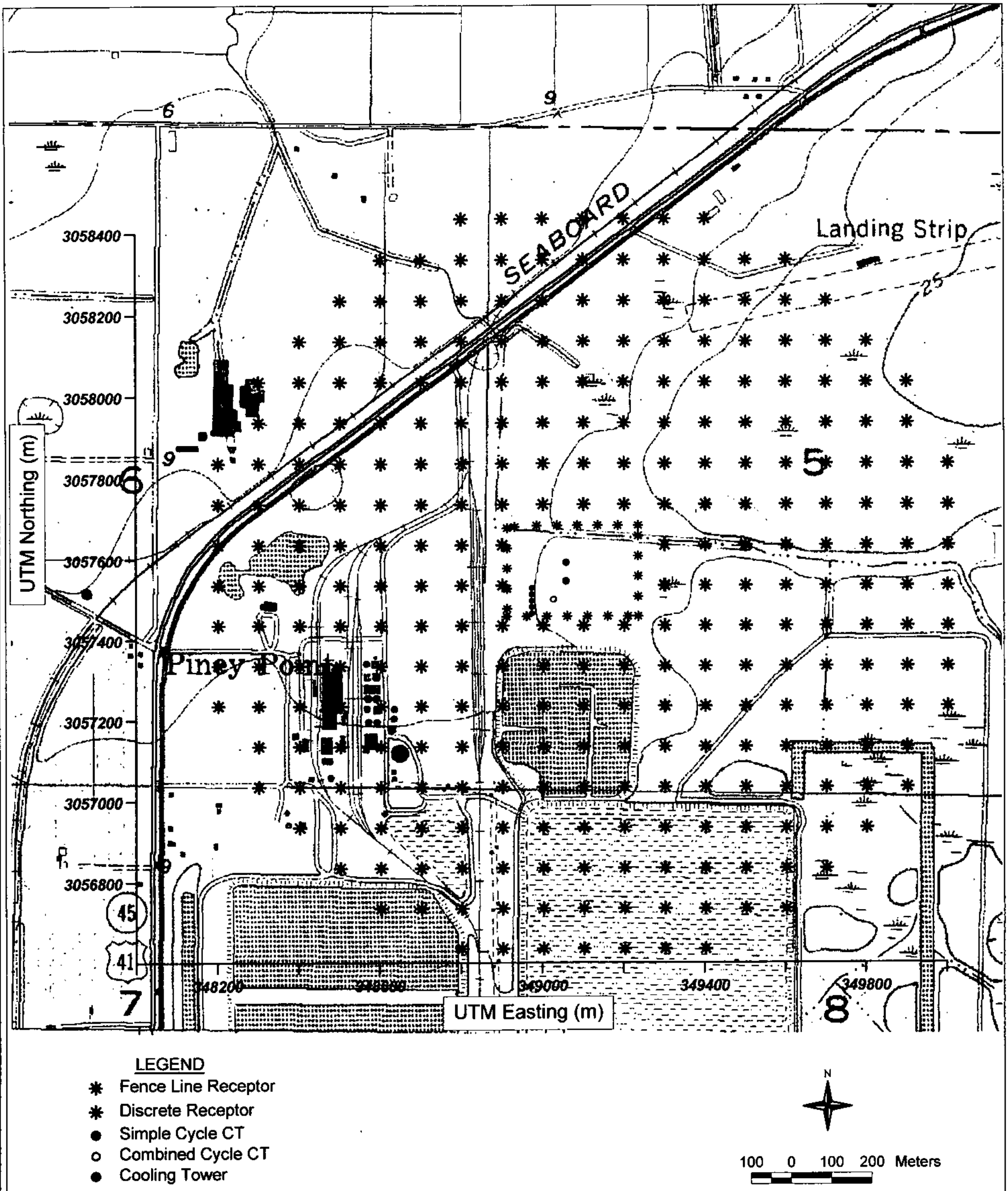

FIGURE 6-3.

RECEPTOR LOCATIONS (WITHIN 1 km)

Sources: USGS Quad: Cockroach Bay, FL, 1981; ECT, 2001.

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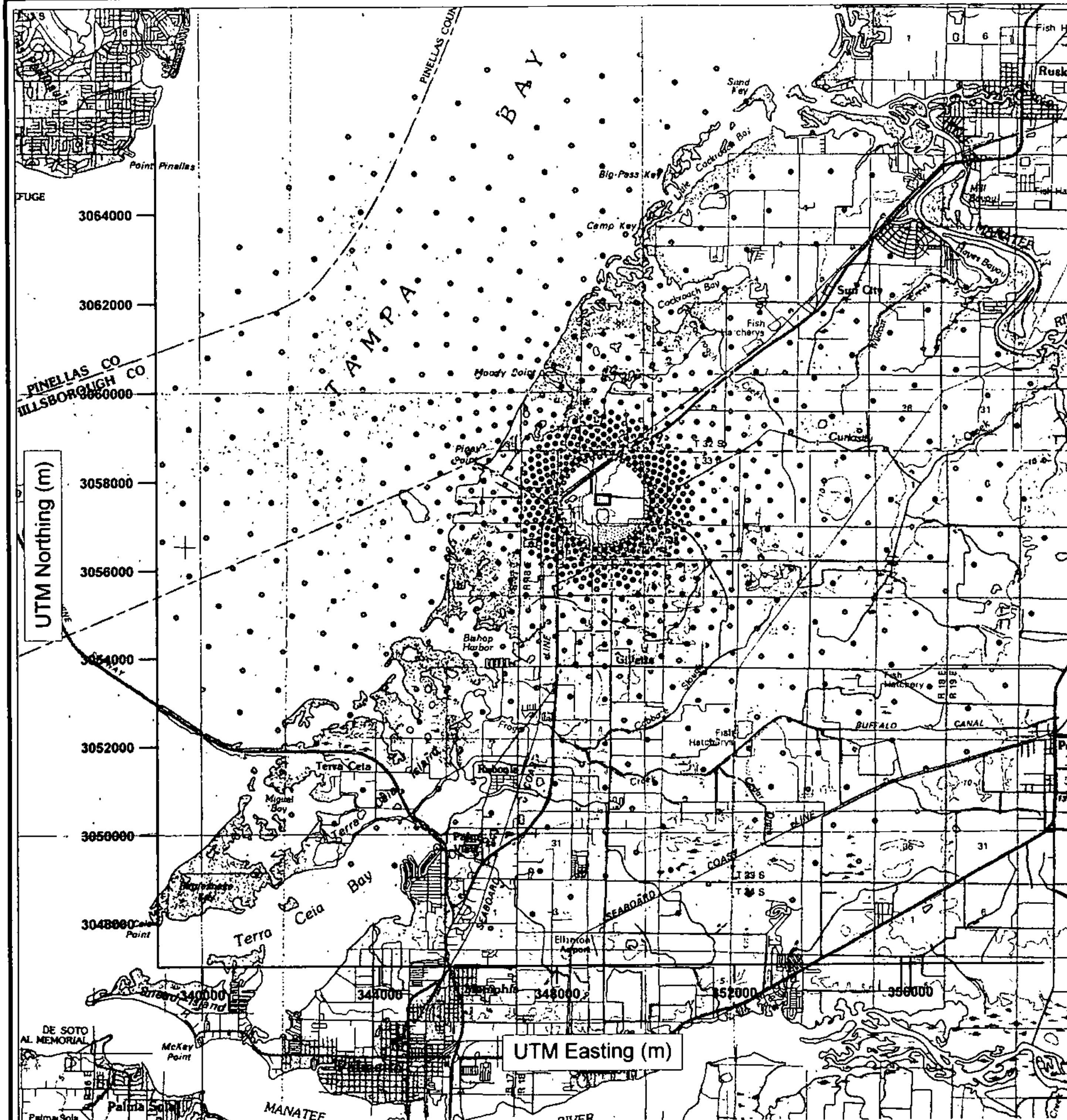

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- Polar Receptors at 10° radial spacing (starting at 5°)
- Polar receptors at 10° radial spacing (starting at 10°)
- Fence line receptors

N

1000 0 1000 2000 Meters

FIGURE 6-4.

RECEPTOR LOCATIONS (FROM 1 km TO 10 km)

Sources: USGS 100,000 Scale Quad: St. Petersburg, FL, 1981; ECT, 2001.

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Models (SCRAM) website are calendar years 1987 through 1991. The Tampa International Airport is located approximately 38 km north of the project site.

The surface and mixing height data for each of the 5 years were processed using the current version of EPA's PCRAMMET (Version 99169) 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.

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 Tampa 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, Tampa station latitude and longitude coordinates (in decimal degrees) are 27.967 and 82.533, respectively. The Tampa surface station is located in time zone 5.

Actual anemometer height for the Tampa surface station, obtained from he National Climatic Data Center (NCDC), is 22 ft (6.7 meters) for the time period of interest (i.e., 1987 through 1991).

Processing of the Tampa station meteorological data did not require any data replacement or substitution.

6.9 MODELED EMISSION INVENTORY

6.9.1 ON-PROPERTY SOURCES

The modeled MEC emission sources included the CC CTG/HRSG unit, two SC CTGs, and cooling tower. In addition to these emission sources, the MEC 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 MEC emission sources were previously presented in Tables 2-1 through 2-8.

As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the MEC emission sources resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods.

6.9.2 OFF-PROPERTY SOURCES

It will be discussed in section 7.0, Ambient Impact Analysis Results, emissions from the MEC resulted in air quality impacts below PSD significant impact levels (reference Table 3-2) for all pollutants and averaging periods. Accordingly, additional multi-source interactive dispersion modeling was not required.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The ISCST3 dispersion model, screening mode, was used to assess each of the 11 SC CTG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; three ambient temperatures [35, 73, and 96 degrees Fahrenheit {°F}]; and one alternative operating mode [inlet air evaporative cooling at 73 and 96°F) for each pollutant subject to the ambient impact analysis (i.e., NO_2, SO_2, PM/PM_{10}, and CO). In addition, the ISCST3 dispersion model, screening mode, was used to assess each of the 14 CC CTG/HRSG operating cases (i.e., a matrix of three CTG loads [100-, 75-, and 50-percent]; four ambient temperatures [35, 59, 73, and 96°F]; and two alternative operating modes [inlet air evaporative cooling and steam mass flow augmentation each at 59, 73, and 96°F] for each pollutant subject to the ambient impact analysis (i.e., NO_2, SO_2, PM/PM_{10}, and CO). These 11 SC CTG and 14 CC CTG/HRSG operating cases represent the expected range of operating conditions for the MEC.

The worst-case SC CTG and CC CTG/HRSG operating cases identified by the ISCST3 screening mode model for each pollutant were then combined to evaluate the worst-case interactive SC CTG and CC CTG/HRSG operating cases. The worst-case interactive SC CTG and CC CTG/HRSG operating modes 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 7-3 provide ISCST3 model (screening mode) maximum 1-hour impacts for NO_2, SO_2, PM/PM_{10}, and CO for the MEC SC CTGs. Table 7-1 indicates, for each SC operating case, the maximum emission rates, ISCST3 screening mode model result based on a nominal 1.0-g/s emission rate, emission rate scaling factor, and scaled

Table 7-1. EPMEC Manatee Energy Center
ISC3 Model (Screening Mode) Input and Results, Simple-Cycle CTs

Case	SC Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (μg/m³)	NO_2			SO_2		
				Emission Rate (g/sec)	Emission Rate Ratio	Maximum 1-Hr Impact (μg/m³)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum 1-Hr Impact (μg/m³)
1	96 °F, 100% Load, EC	1.00	0.945	6.804	6.80	6.4	0.858	0.86	0.8
2	96 °F, 100% Load	1.00	1.041	6.552	6.55	6.8	0.833	0.83	0.9
3	96 °F, 75% Load	1.00	2.046	5.418	5.42	11.1	0.685	0.69	1.4
4	96 °F, 50% Load	1.00	3.122	4.284	4.28	**13.4**	0.548	0.55	**1.7**
5	73 °F, 100% Load, EC	1.00	0.805	7.182	7.18	5.8	0.904	0.90	0.7
6	73 °F, 100% Load	1.00	0.846	7.056	7.06	6.0	0.891	0.89	0.8
7	73 °F, 75% Load	1.00	1.888	5.670	5.67	10.7	0.723	0.72	1.4
8	73 °F, 50% Load	1.00	2.939	4.536	4.54	13.3	0.580	0.58	1.7
9	35 °F, 100% Load	1.00	0.830	7.686	7.69	6.4	0.965	0.96	0.8
10	35 °F, 75% Load	1.00	1.732	6.048	6.05	10.5	0.770	0.77	1.3
11	35 °F, 50% Load	1.00	2.769	4.788	4.79	13.3	0.617	0.62	1.7
	Maximums					**13.4**			**1.7**

Case	SC Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (μg/m³)	PM/PM_{10}			CO		
				Emission Rate (g/sec)	Emission Rate Ratio	Maximum 1-Hr Impact (μg/m³)	Emission Rate (g/sec)	Emission Rate Ratio	Maximum 1-Hr Impact (μg/m³)
1	96 °F, 100% Load, EC	1.00	0.945	2.306	2.31	2.2	3.402	3.40	3.2
2	96 °F, 100% Load	1.00	1.041	2.306	2.31	2.4	3.276	3.28	3.4
3	96 °F, 75% Load	1.00	2.046	2.293	2.29	4.7	2.646	2.65	5.4
4	96 °F, 50% Load	1.00	3.122	2.293	2.29	**7.2**	2.268	2.27	**7.1**
5	73 °F, 100% Load, EC	1.00	0.805	2.306	2.31	1.9	3.528	3.53	2.8
6	73 °F, 100% Load	1.00	0.846	2.306	2.31	2.0	3.528	3.53	3.0
7	73 °F, 75% Load	1.00	1.888	2.306	2.31	4.4	2.898	2.90	5.5
8	73 °F, 50% Load	1.00	2.939	2.293	2.29	6.7	2.394	2.39	7.0
9	35 °F, 100% Load	1.00	0.830	2.306	2.31	1.9	3.906	3.91	3.2
10	35 °F, 75% Load	1.00	1.732	2.306	2.31	4.0	3.024	3.02	5.2
11	35 °F, 50% Load	1.00	2.769	2.293	2.29	6.4	2.520	2.52	7.0
	Maximums					**7.2**			**7.1**

EC = evaporative cooling.

Source: ECT, 2001.

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Table 7-2. EPMEC Manatee Energy Center
ISC3 Model (Screening Mode) Input and Results, Combined -Cycle CT

GE Case	CC Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (μg/m³)	NO_2 Emission Rate (g/sec)	NO_2 Emission Rate Ratio	NO_2 Maximum 1-Hr Impact (μg/m³)	SO_2 Emission Rate (g/sec)	SO_2 Emission Rate Ratio	SO_2 Maximum 1-Hr Impact (μg/m³)
1	96 °F, 100% Load, EC	1.00	5.130	2.659	2.66	13.6	0.858	0.86	4.4
2	96 °F, 100% Load	1.00	5.303	2.608	2.61	13.8	0.834	0.83	4.4
3	96 °F, 75% Load	1.00	7.125	2.117	2.12	**15.1**	0.687	0.69	**4.9**
4	96 °F, 50% Load	1.00	8.767	1.676	1.68	14.7	0.548	0.55	4.8
5	73 °F, 100% Load, EC	1.00	4.643	2.797	2.80	13.0	0.904	0.90	4.2
6	73 °F, 100% Load	1.00	4.719	2.747	2.75	13.0	0.891	0.89	4.2
7	73 °F, 75% Load	1.00	6.419	2.218	2.22	14.2	0.724	0.72	4.7
8	73 °F, 50% Load	1.00	8.137	1.764	1.76	14.4	0.578	0.58	4.7
9	35 °F, 100% Load	1.00	4.113	2.999	3.00	12.3	0.965	0.96	4.0
10	35 °F, 75% Load	1.00	5.580	2.356	2.36	13.1	0.773	0.77	4.3
11	35 °F, 50% Load	1.00	7.413	1.879	1.88	13.9	0.620	0.62	4.6
12	96 °F, 100% Load, EC, MFA	1.00	4.879	2.770	2.77	13.5	0.899	0.90	4.4
13	73 °F, 100% Load, EC, MFA	1.00	4.385	2.902	2.90	12.7	0.942	0.94	4.1
14	59 °F, 100% Load, EC, MFA	1.00	4.149	2.968	2.97	12.3	0.963	0.96	4.0
Maximums						**15.1**			**4.9**

GE Case	CC Operating Scenario	Modeled Emission Rate (g/sec)	ISC3 Results 1-Hour Impact (μg/m³)	PM/PM_{10} Emission Rate (g/sec)	PM/PM_{10} Emission Rate Ratio	PM/PM_{10} Maximum 1-Hr Impact (μg/m³)	CO Emission Rate (g/sec)	CO Emission Rate Ratio	CO Maximum 1-Hr Impact (μg/m³)
1	96 °F, 100% Load, EC	1.00	5.130	2.520	2.52	12.9	3.402	3.40	17.5
2	96 °F, 100% Load	1.00	5.303	2.520	2.52	13.4	3.276	3.28	17.4
3	96 °F, 75% Load	1.00	7.125	2.394	2.39	17.1	2.646	2.65	18.9
4	96 °F, 50% Load	1.00	8.767	2.394	2.39	**21.0**	2.268	2.27	19.9
5	73 °F, 100% Load, EC	1.00	4.643	2.520	2.52	11.7	3.528	3.53	16.4
6	73 °F, 100% Load	1.00	4.719	2.520	2.52	11.9	3.528	3.53	16.6
7	73 °F, 75% Load	1.00	6.419	2.394	2.39	15.4	2.898	2.90	18.6
8	73 °F, 50% Load	1.00	8.137	2.394	2.39	19.5	2.394	2.39	19.5
9	35 °F, 100% Load	1.00	4.113	2.520	2.52	10.4	3.906	3.91	16.1
10	35 °F, 75% Load	1.00	5.580	2.394	2.39	13.4	3.024	3.02	16.9
11	35 °F, 50% Load	1.00	7.413	2.394	2.39	17.7	2.591	2.59	19.2
12	96 °F, 100% Load, EC, MFA	1.00	4.879	2.520	2.52	12.3	5.628	5.63	**27.5**
13	73 °F, 100% Load, EC, MFA	1.00	4.385	2.520	2.52	11.1	5.926	5.93	26.0
14	59 °F, 100% Load, EC, MFA	1.00	4.149	2.520	2.52	10.5	6.103	6.10	25.3
Maximums						**21.0**			**27.5**

EC = evaporative cooling.
MFA = mass flow augmentation.

Source: ECT, 2001.

Table 7-3. EPMEC Manatee Energy Center
ISC3 Model (Screening Mode) Results, CC1, SC1, SC2, and CT1 - CT5

CC - GE Case	CC Operating Scenario	1-Hour Maximum Impacts			
		NO_2 ISC3 Results (μg/m^3)	SO_2 ISC3 Results (μg/m^3)	PM_{10} ISC3 Results (μg/m^3)	CO ISC3 Results (μg/m^3)
1	96 °F, 100% Load, EC	23.479	4.972	16.999	20.009
2	96 °F, 100% Load	23.440	4.930	17.148	19.725
3	96 °F, 75% Load	22.294	4.895	17.509	18.853
4	96 °F, 50% Load	20.803	4.804	**21.381**	19.884
5	73 °F, 100% Load, EC	23.549	5.000	16.533	19.916
6	73 °F, 100% Load	23.448	4.978	16.607	20.019
7	73 °F, 75% Load	22.457	4.676	17.169	18.948
8	73 °F, 50% Load	21.062	4.703	19.871	19.481
9	35 °F, 100% Load	23.501	4.966	15.814	20.256
10	35 °F, 75% Load	22.633	4.745	16.710	18.950
11	35 °F, 50% Load	21.392	4.596	18.134	19.207
12	96 °F, 100% Load, EC, MFA	**23.645**	**5.044**	16.766	28.563
13	73 °F, 100% Load, EC, MFA	23.616	5.035	16.258	**28.662**
14	59 °F, 100% Load, EC, MFA	23.499	4.995	15.937	28.565
	Maximums	**23.645**	**5.044**	**21.381**	**28.662**

EC = evaporative cooling.
MFA = mass flow augmentation.
SC1-SC3 data for SC-GE Case No. 4.
PM_{10} runs include cooling tower cells CT1-CT5.

Source: ECT, 2001.

ISCST3 screening mode model result. As shown in ISCST3 model (screening mode) summary Table 7-1, maximum 1-hour impacts for SC-1 and SC-2 are projected to occur under Case 4 operating conditions (i.e., 50-percent load, and 96°F ambient) for all pollutants.

Table 7-2 indicates, for each CC CTG/HRSG operating case, the maximum emission rates, ISCST3 screening mode model result based on a nominal 1.0-g/s emission rate, emission rate scaling factor, and scaled ISCST3 screening mode model result. As shown in ISCST3 model (screening mode) summary Table 7-2, the maximum NO_x and SO_2 1 hour impacts are projected to occur under Case 3 CC CTG/HRSG operating conditions (i.e., 75 percent load and 96°F ambient temperature). Maximum CO 1 hour impact for the CC CTG/HRSG is projected to occur under Case 12 CC CTG/HRSG operating conditions (i.e., 100 percent load, evaporative cooling, steam mass flow augmentation, and 96°F ambient temperature). Maximum 1-hour PM_{10} impacts for the CC CTG/HRSG are projected to occur under Case 4 CC CTG/HRSG operating conditions (i.e., 50 percent load, and 96°F ambient temperature).

To determine maximum interactive CC CTG/HRSG and SC CTG impacts, the worst case SC CTG operating scenario (Case 4) was evaluated with each of the 14 CC CTG/HRSG operating scenarios. As shown in ISCST3 model (screening mode) summary Table 7-3, maximum NO_x and SO_2 1-hour impacts for the CC CTG/HRSG and SC CTGs are projected to occur under Case 12 CC CTG/HRSG operating conditions (i.e., 100-percent load, evaporative cooling, steam mass flow augmentation, and 96°F ambient temperature). Maximum 1-hour PM_{10} impacts for the CC CTG/HRSG, SC CTGs, and the cooling tower are projected to occur under Case 4 CC CTG/HRSG operating conditions (i.e., 50-percent load, and 96°F ambient temperature). Maximum 1-hour CO impacts for the CC CTG/HRSG and SC CTGs are projected to occur under Case 13 CC CTG/HRSG operating conditions (i.e., 100-percent load, evaporative cooling, steam mass flow augmentation, and 73°F ambient temperature). These worst-case interactive CC CTG/HRSG and SC CTG operating modes were then further analyzed using the ISCST3 refined mode dispersion model.

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 7-4 (annual NO_2 impacts), Table 7-5 (annual SO_2 impacts), Table 7-6 (annual PM_{10} impacts), Table 7-7 (3-hour SO_2 impacts), Table 7-8 (24-hour SO_2 impacts), Table 7-9 (24-hour PM/PM_{10} impacts), Table 7-10 (1-hour CO impacts), and Table 7-11 (8-hour CO impacts).

Tables 7-4 through 7-11 demonstrate that MEC impacts, for all pollutants and all averaging times, will be below the PSD significant impact levels previously shown in Table 4-2. Table 7-12 provides a summary comparison of the maximum MEC impacts for each year of meteorology evaluated (1987 to 1991) and the PSD significant impact levels.

7.3 PSD CLASS I IMPACTS

Maximum impacts at the nearest PSD Class I area (Chassahowitzka NWR), located approximately 110 km north of the MEC site, were estimated using the CALPUFF dispersion model in refined mode, including the CALMET and CALPOST pre- and post-processing programs. In addition, these programs were utilized to develop estimates of impacts on regional haze and deposition. The results of these Class I impact analyses are presented in Section 10.0 (Class I Impacts).

7.4 SULFURIC ACID MIST

The maximum MEC 1-hour average ISCST3 model (screening mode) impact was 5.04 micrograms per cubic meter ($\mu g/m^3$) for SO_2, based on a nominal 1.0 g/s emission rate. Because H_2SO_4 mist emissions are proportional to SO_2 emissions (by a conservative factor of 0.183 on a lb/hr basis assuming 8.0-percent conversion of fuel sulfur to SO_3 by the CTG, 4.0-percent conversion of SO_2 to SO_3 by the SCR control system, and

Table 7-4. ISCST3 Model Results - Maximum Annual Average NO_2 Impacts

Maximum Annual Impacts	1987	1988	1989	**1990**	1991
Tier 1 ISCST3 Impact ($\mu g/m^3$)[1]	0.040	0.035	0.037	**0.042**	0.040
Tier 2 ISCST3 Impact ($\mu g/m^3$)[2]	0.030	0.026	0.028	**0.031**	0.030
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 (%)	3.0	2.6	2.8	**3.1**	3.0
Receptor UTM Easting (m)	351,854.4	343,640.7	349,581.9	**342,342.9**	340,877.2
Receptor UTM Northing (m)	3,057,535.0	3,051,023.5	3,060,243.3	**3,055,723.3**	3,052,785.0
Distance From SC-1 (m)	2,794	8,480	2,748	**6,960**	9,467
Direction From SC-1 (Vector °)	90	220	11	**255**	240

Note: Maximum impact shown in bold type.

[1] ISCST3 impact (assume complete conversion of NO_x to NO_2).

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

Source: ECT, 2001.

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Table 7-5. ISCST3 Model Results - Maximum Annual Average SO_2 Impacts

Maximum Annual Impacts	**1987**	1988	1989	1990	1991
ISCST3 Impact ($\mu g/m^3$)	**0.012**	0.009	0.011	0.011	0.010
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 (%)	**1.2**	0.9	1.1	1.1	1.0
Receptor UTM Easting (m)	**351,354.4**	344,283.5	349,495.1	351,594.9	340,877.2
Receptor UTM Northing (m)	**3,057,535.0**	3,051,789.8	3,059,750.8	3,057,753.0	3,052,785.0
Distance From SC-1 (m)	**2,294**	7,479	2,248	2,543	9,467
Direction From SC-1 (Vector °)	**90**	220	11	85	240

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Table 7-6. ISCST3 Model Results - Maximum Annual Average PM_{10} Impacts

Maximum Annual Impacts	1987	1988	**1989**	1990	1991
ISCST3 Impact (µg/m^3)	0.059	0.061	**0.063**	0.059	0.060
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 (%)	5.9	6.1	**6.3**	5.9	6.0
Receptor UTM Easting (m)	350,698.3	347,015.3	**349,399.6**	350,698.3	345,207.3
Receptor UTM Northing (m)	3,057,395.5	3,055,045.3	**3,059,209.3**	3,057,674.5	3,055,285.0
Distance From SC-1 (m)	1,645	3,230	**1,698**	1,643	4,467
Direction From SC-1 (Vector °)	95	219	**12**	85	240

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Table 7-7. ISCST3 Model Results - Maximum 3-Hour Average SO_2 Impacts

Maximum 3-Hour Impacts	1987	**1988**	1989	1990	1991
ISCST3 Impact (µg/m^3)	0.94	**0.83**	0.52	0.66	
PSD Significant Impact (µg/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 (%)	3.8	**3.3**	2.1	2.6	0.0
Receptor UTM Easting (m)	349,204.4	**348,904.4**	348,354.4	349,204.4	
Receptor UTM Northing (m)	3,057,735.0	**3,057,335.0**	3,058,834.0	3,057,235.0	
Distance From SC-1 (m)	238	**262**	1,470	342	3,077,405
Direction From SC-1 (Vector °)	37	**217**	331	155	187
Date of Maximum Impact	6/19/87	**11/23/88**	6/22/89	10/25/90	4/27/91
Julian Date of Maximum Impact	170	**328**	173	298	117
Ending Hour of Maximum Impact	1800	**0300**	1200	1500	1500

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

Table 7-8. ISCST3 Model Results - Maximum 24-Hour Average SO_2 Impacts

Maximum 24-Hour Impacts	1987	1988	**1989**	1990	1991
ISCST3 Impact (μg/m^3)	0.13	0.17	**0.15**	0.14	
PSD Significant Impact (μg/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 (%)	2.6	3.5	**3.1**	2.8	0.0
PSD *de minimis* Ambient Impact Threshold (μg/m^3)	13.0	13.0	**13.0**	13.0	13.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	**N**	N	N
Percent of PSD *de minimis* Ambient Impact (%)	1.0	1.3	**1.2**	1.1	0.0
Receptor UTM Easting (m)	345,207.3	349,212.8	**349,751.4**	351,594.9	
Receptor UTM Northing (m)	3,055,285.0	3,057,457.3	**3,055,120.3**	3,057,753.0	
Distance From SC-1 (m)	4,467	262	**2,521**	2,543	3,077,405
Direction From SC-1 (Vector °)	240	217	**164**	85	187
Date of Maximum Impact	10/4/87	4/12/88	**7/4/89**	6/20/90	5/14/91
Julian Date of Maximum Impact	277	103	**185**	171	134

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

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Table 7-9. ISCST3 Model Results - Maximum 24-Hour Average PM_{10} Impacts

Maximum 24-Hour Impacts	1987	**1988**	1989	1990	1991
ISCST3 Impact ($\mu g/m^3$)	0.80	**1.49**	0.65	0.89	0.65
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 (%)	16.1	**29.8**	13.0	17.8	12.9
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)	N	**N**	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	8.0	**14.9**	6.5	8.9	6.5
Receptor UTM Easting (m)	349,204.4	**349,204.4**	348,334.8	349,204.4	351,486.0
Receptor UTM Northing (m)	3,057,235.0	**3,057,335.0**	3,055,420.8	3,057,335.0	3,056,160.0
Distance From SC-1 (m)	342	**255**	2,245	255	2,793
Direction From SC-1 (Vector °)	155	**146**	199	146	120
Date of Maximum Impact	1/11/87	**3/10/88**	10/28/89	10/25/90	4/21/91
Julian Date of Maximum Impact	11	**63**	301	298	111

Note: Maximum impact shown in bold.

Source: ECT, 2001.

Table 7-10. ISCST3 Model Results - Maximum 1-Hour Average CO Impacts

Maximum 1-Hour Impacts	**1987**	1988	1989	1990	1991
ISCST3 Impact ($\mu g/m^3$)	**17.2**	12.9	5.4	11.8	14.1
PSD Significant Impact ($\mu g/m^3$)	**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 (%)	**0.9**	0.6	0.3	0.6	0.7
Receptor UTM Easting (m)	**349,204.4**	348,804.4	348,904.4	349,204.4	349,004.4
Receptor UTM Northing (m)	**3,057,735.0**	3,057,135.0	3,057,735.0	3,057,235.0	3,057,335.0
Distance From SC-1 (m)	**238**	483	246	342	217
Direction From SC-1 (Vector °)	**37**	212	321	155	195
Date of Maximum Impact	**6/19/87**	11/23/88	5/4/89	10/25/90	3/10/91
Julian Date of Maximum Impact	**170**	328	124	298	69
Ending Hour of Maximum Impact	**1700**	0200	2200	1500	0700

Note: Maximum impact shown in bold type.

Source: ECT, 2001.

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Table 7-11. ISCST3 Model Results - Maximum 8-Hour Average CO Impacts

Maximum 8-Hour Impacts	1987	1988	**1989**	1990	1991
ISCST3 Impact (µg/m^3)	2.46	1.94	**2.51**	2.17	2.35
PSD Significant Impact (µg/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 (%)	0.5	0.4	**0.5**	0.4	0.5
PSD *de minimis* Ambient Impact Threshold (µg/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 (%)	0.4	0.3	**0.4**	0.4	0.4
Receptor UTM Easting (m)	349,204.4	349,278.7	**349,278.7**	351,320.2	349,004.4
Receptor UTM Northing (m)	3,057,735.0	3,059,527.5	**3,059,527.5**	3,057,144.3	3,057,335.0
Distance From SC-1 (m)	238	1,994	**1,994**	2,295	217
Direction From SC-1 (Vector °)	37	6	**6**	100	195
Date of Maximum Impact	6/19/87	5/24/88	**6/9/89**	6/24/90	3/10/91
Julian Date of Maximum Impact	170	145	**160**	175	69
Ending Hour of Maximum Impact	2400	1600	**1600**	1600	0800

Note: Maximum impact shown in bold type.

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Table 7-12. ISCST3 Model Results-Maximum Criteria Pollutant Impacts, 1987-1991 Meteorology

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)	Significant Impact (%)	Exceed Significant Impact (Yes/No)
CO	8-Hour	2.51	500	0.5	No
	1-Hour	17.20	2,000	0.9	No
PM/PM_{10}	Annual	0.06	1.0	6.3	No
	24-Hour	2.25	5.0	45.0	No
SO_2	Annual	0.01	1.0	1.2	No
	24-Hour	0.17	5.0	3.5	No
	3-Hour	0.94	25.0	3.8	No
NO_x	Annual	0.04	1.0	4.2	No

Source: ECT, 2001.

100-percent conversion of SO_3 to H_2SO_4), and because ambient air quality impacts are directly proportional to emission rates (all other variables remaining the same), the maximum 1-hour ISCST3 modeled impact for H_2SO_4 mist is calculated to be 0.92 $\mu g/m^3$. Recommended EPA (EPA, 1992) factors for converting 1-hour averages to 8- and 24-hour averages are 0.7 and 0.4, respectively. Use of these factors yields maximum 8- and 24-hour average H_2SO_4 mist impacts of 0.64 and 0.37 $\mu g/m^3$, respectively. Draft FDEP H_2SO_4 mist acceptable reference concentrations (ARCs) for 8- and 24-hour averaging periods are 10.0 and 2.4 $\mu g/m^3$, respectively.

7.5 CONCLUSIONS

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

- Below the PSD Class II significant impact levels for all pollutants and all averaging periods.
- Below the PSD Class II *de-minimis* ambient impact levels for all pollutants and all averaging periods.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest ambient air monitoring station is located off Buckeye Road, Manatee County, approximately 0.1 km south of the project site. The Manatee County local program monitoring station (AIRS No. 081-0008) located off Buckeye Road monitors for PM_{10}. The nearest station (AIRS No. 081-3002, operated by the Manatee County local program) that monitors for ozone and SO_2 is located at Port Manatee in Palmetto, Manatee County, approximately 1.2 km northwest of the project site. The nearest station (AIRS No. 081-4012, operated by the Manatee County local program and the FDEP) that monitors for NO_2 and $PM_{2.5}$ is located in Bradenton, Manatee County, approximately 17.7 km southwest of the project site. The nearest station (AIRS No. 057-1074, operated by the Hillsborough County local program) that monitors for CO is located in Tampa, Hillsborough County, approximately 41 km north of the project site. The nearest station (AIRS No. 057-1066, operated by the Hillsborough County local program) monitoring for lead is situated in Tampa, Hillsborough County, approximately 40 km northeast of the project site. Summaries of 1998 and 1999 ambient air quality data for these ambient air stations are provided on 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 MEC 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

Table 8-1. Summary of 1998 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	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}	Manatee	Piney Point	081-0008	0.1 S	24-Hr	Jan-Dec	39	56	43	56		150[1]
					Annual						25[5]	50[2]
SO_2	Manatee	Palmetto	081-3002	1.2 NW	1-Hr	Jan-Dec	2,179	335	306			
					3-Hr			277	225			1,300[3]
					24-Hr			89	50			260[3]
					Annual						13[5]	60[2]
SO_2	Hillsborough	Tampa	057-0081	15 NE	1-Hr	Jan-Dec	8,454	314	264			
					3-Hr			196	194			1,300[3]
					24-Hr			63	52			260[3]
					Annual						10	60[2]
NO_2	Hillsborough	Tampa	057-0081	15 NE	1-Hr	Jan-Dec	8,353	98	83			
					Annual						11	100[2]
CO	Hillsborough	Tampa	057-1070	41 N	1-Hr	Jan-Dec	8,698	9,276	7,902			40,000[3]
					8-Hr			4,695	4,695			10,000[3]
O_3	Manatee	Palmetto	081-3002	1.2 NW	1-Hr	Jan-Dec	235	261	230			235[4]
Lead	Hillsborough	Tampa	057-1066	40 NE	24-Hr		59					
						Jan-Mar					0.41	1.5[2]
						Apr-Jun					0.51	
						Jul-Sep					0.27	
						Oct-Dec					0.37	

[1] 99th percentile

[2] Arithmetic mean

[3] 2nd high

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

[5] Indicates that the mean does not sastify summary criteria

Source: FDEP, 1999 and 2000.
ECT, 2001.

Table 8-2. Summary of 1999 FDEP Ambient Air Quality Data

Pollutant	Site Location		Site No.	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}	Manatee	Piney Point	081-0008	0.1 S	24-Hr	Jan-Dec	55	48	42	48		150[1]
					Annual						24	50[2]
SO_2	Manatee	Palmetto	081-3002	1.2 NW	1-Hr	Jan-Dec	8,662	343	304			
					3-Hr			157	147			1,300[3]
					24-Hr			55	44			260[3]
					Annual						10	60[2]
NO_2	Manatee	Bradenton	081-4012	17.7 SW	1-Hr	Jan-Dec	8,633	77	77			
					Annual						13	100[2]
CO	Hillsborough	Tampa	057-1070	41 N	1-Hr	Jan-Dec	8,725	6,986	6,642			40,000[3]
					8-Hr			4,466	3,779			10,000[3]
O_3	Manatee	Palmetto	081-3002	1.2 NW	1-Hr	Jan-Dec	243	220	218			235[4]
Lead	Hillsborough	Tampa	057-1066	40 NE	24-Hr		60					
						Jan-Mar					0.42	1.5[2]
						Apr-Jun					0.41	
						Jul-Sep					0.42	
						Oct-Dec					1.02	

[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, 1999 and 2000.
ECT, 2001.

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MEC. The results of these analyses are presented in detail in Section 7.2. The following paragraphs 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 2.3 $\mu g/m^3$. This concentration is below the 10 $\mu g/m^3$ *de minimis* level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 2.5 $\mu g/m^3$. 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 0.04 $\mu g/m^3$. 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 0.17 $\mu g/m^3$. 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. Potential VOC emissions from the MEC will not exceed this threshold. Therefore, a preconstruction monitoring exemption is appropriate for ozone in accordance with the FDEP PSD regulations.

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 MEC and to assess air quality impacts that would result from that growth.

Impacts associated with construction of the MEC 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 MEC is being constructed to meet general area electric power demands and, therefore, no significant secondary growth effects due to operation of the MEC are anticipated. When operational, the MEC is projected to generate approximately 25 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 MEC 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. The highest predicted SO_2 concentration increases due to MEC emissions are a 3-hour concentration of 0.94 $\mu g/m^3$, a 24-hour concentration of 0.17 $\mu g/m^3$, and an annual average concentration of 0.012 $\mu g/m^3$. The predicted concentrations of other pollutants are equally low. For instance, the highest modeled annual average NO_2 concentration increase due to MEC emissions is 0.042 $\mu g/m^3$. 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

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 μg/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 intercoastal 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 μg/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 $\mu g/m^3$ (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 $\mu g/m^3$ for 6 weeks. Tolerant lichens can resist SO_2 concentrations in the range of 79 to 157 $\mu g/m^3$; higher concentrations are deleterious to most nonvascular flora (LeBlanc and Rao, 1975).

The maximum total 3-hour average SO_2 concentrations for the MEC is projected to be 0.94 $\mu g/m^3$. The maximum total predicted 24-hour average SO_2 concentration is 0.17 $\mu g/m^3$. Annually, the concentration is predicted to be 0.012 $\mu g/m^3$. 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 MEC 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 MEC is 0.042 $\mu g/m^3$. 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 the MEC 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 MEC 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 MEC 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 MEC. Opacity of the MEC CC CTG/HRSG unit and SC CTG exhausts will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the MEC CC CTG/HRSG and SC CTGs will be low due to the exclusive use of pipeline quality natural gas. The MEC will comply with all applicable FDEP requirements pertaining to visible emissions.

10.0 CLASS I IMPACTS

10.1 INTRODUCTION

The required Class I area impact assessments were conducted using the CALPUFF dispersion model in accordance with the recommendations contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts.* The CALPUFF model was employed in a refined mode using one year (1990) of meteorology developed using the CALMET pre-processor program and specific receptors recommended by FDEP for the Chassahowitzka National Wildlife Refuge (NWR). The CALPUFF suite of programs, including the CALPOST post-processing program, was employed to develop estimates of MEC impacts on the Chassahowitzka NWR for PSD increments, regional haze, and deposition.

10.2 SUMMARY

The CALMET/CALPUFF/CALPOST modeling assessment resulted in the following conclusions:

- Maximum SO_2, NO_2, and PM_{10} impacts at the Chassahowitzka NWR are projected to be well below the EPA Class I area significant levels for all pollutants and averaging periods. The critical averaging time and pollutant was determined to be the 24-hour average PM_{10} impact. Maximum 24-hour average PM_{10} impact on the Chassahowitzka NWR is projected to be 0.026 $\mu g/m^3$, or only 8.6 percent of the EPA PSD Class I significant impact level. The EPA PSD Class I significant impact levels were previously provided in Section 4.0, Table 4-3.
- Maximum change in light extinction coefficient (β_{ext}) at the Chassahowitzka NWR is projected to be 0.41 percent or a 0.041 change in deciview (dv). These visibility impacts are below the National Park Service (NPS) significance levels of a 5 percent change in β_{ext} and 0.5 change in dv.
- Maximum total (wet and dry) sulfur and nitrogen deposition rates are projected to be 0.00075 and 0.00116 kilograms per hectare per year (kg/ha/yr), respectively. These deposition impacts are only 1.5 and 2.3 percent of the

NPS significance level of 0.05 kg/ha/yr for sulfur and nitrogen deposition, respectively.

10.3 MODEL SELECTION AND USE

The nearest Class I area to the proposed MEC is the Chassahowitzka NWR, located approximately 110 km north of the project site. Steady-state dispersion models do not consider temporal or spatial variations in plume transport direction nor do they limit the downwind transport of a pollutant as a function of wind speed and travel time. Due to these limitations, conventional steady-state dispersion models, such as the Industrial Source Complex (ISC) models, are not considered suitable for predicting air quality impacts at receptors located more than 50 km from an emission source.

Because of the need to assess air quality impacts at PSD Class I areas, which are typically located at distances greater than 50 km from the emission sources of interest, the EPA and Federal Land Managers (FLMs) have initiated efforts to develop dispersion models appropriate for the assessment of long-range transport of air pollutants. The Interagency Workgroup for Air Quality Modeling (IWAQM) was formed to coordinate the model development efforts of the EPA and FLMs.

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

The Phase 1 recommendation, issued in April 1993, is to use the Lagrangian puff model, MESOPUFF II, for long-range transport air quality assessments.

The Phase 2 recommendations, issued in December 1998, are contained in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*. The Phase 2 IWAQM recommendation is to apply the CALPUFF Modeling System to assess air quality impacts at distances greater than 50 km from an emission source. The CALPUFF Modeling System consists of three main components: (a) CALMET, (b) CALPUFF, and (c) CALPOST. Each of these components is described in the following sections.

10.4 CALMET

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

CALMET requires a number of input data files to develop the gridded three- and two-dimensional meteorological file utilized by CALPUFF. The specific meteorological data, and example file names, provided as input to the CALMET program include:

- Penn State/NCAR Mesoscale Model gridded, prognostic wind field data (terrain elevation, land use code, sea level pressure, rainfall amount, snow cover indicator, pressure, temperature/dew point, wind direction, and wind speed) [MM4.DAT].
- Surface station weather data (windspeed, wind direction, ceiling height, opaque sky cover, air temperature, relative humidity, station pressure, and precipitation type code) [SURF.DAT].
- Upper air sounding (mixing height) data (pressure, height above sea level, temperature, wind direction, and wind speed at each sounding) [UP1.DAT];
- Surface station precipitation data (precipitation rates) [PRECIP.DAT].
- Overwater data (air-sea surface temperature difference, air temperature, relative humidity, overwater mixing height, wind speed, and wind direction) [SEA1.DAT].
- Geophysical data (land use type, terrain elevation, surface parameters including surface roughness, length, albedo, Bowen ratio, soil heat flux, and vegetation leaf area index, and anthropogenic heat flux) [GEO.DAT].

The above CALMET input files for calendar year 1990, with the exception of precipitation data, were obtained from the FDEP for use in assessing air quality impacts at the Chassahowitzka NWR. Further details regarding the specific surface and upper air stations used in the CALMET program are provided in Section 10.8, Meteorological Data.

The various CALMET program options are implemented by means of a control file. CALMET options selected for the MEC Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase 2 report. The product of the CALMET program is a large (approximately one gigabyte) unformatted file that is provided as input to the CALPUFF program. CALMET Version 5.2, Level 000602A was used in the MEC Chassahowitzka NWR air quality impact assessments.

10.5 CALPUFF

CALPUFF is a transport and puff model that advects "puffs" of material from an emission source. These "puffs" undergo various dispersion and transformation simulation processes as they are advected from an emission source to a receptor of interest. The simulation processes include wet and dry deposition and chemical transformation. CALPUFF typically uses the gridded meteorological data created by the CALMET program. CALPUFF, when used in a screening mode, can also utilize non-gridded meteorological data similar to that used by a steady-state Gaussian model such as the ISC dispersion model. The distribution of puffs by CALPUFF explicitly incorporates the temporal and spatial variations in the meteorological fields thereby overcoming one of the main shortcomings of steady-state dispersion models.

There are a number of optional CALPUFF input files that were not used for the Chassahowitzka NWR impact assessments. These include time-varying emission rates, hourly ambient ozone data, user-specified deposition velocities and chemical transformation conversion rates, complex terrain receptor and hill geometry data, and coastal boundary data.

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

The various CALPUFF program options are implemented by means of a control file. CALPUFF options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase 2 report. Options selected include modeling of six species (SO_2, SO_4, NO_x, HNO_3, NO_3, and PM_{10}), chemical transformation using the MESOPUFF II scheme, wet removal, and a 25 by 28 meteorological and computational grid with a 10-km grid spacing. The meteorological and computational grid includes the MEC emission sources and the Chassahowitzka NWR receptors. The current version of CALPUFF (Version 5.4, Level 0006021) was used in the Chassahowitzka NWR air quality impact assessments.

10.6 CALPOST

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

For visibility assessments, background conditions were estimated using 1994–1998 seasonal, clear-day, speciated particulate matter (aerosol) profile data collected at the Chassahowitzka NWR Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring site. The IMPROVE data for the visibility assessments, which was obtained from the NPS' Web site, is conservative in that the cleanest 10% visibility data was used. The IWQAM Phase 2 report recommends use of the cleanest 20% background visibility data as representing clear-day conditions. However, the 20% profile data is not available at the NPS Web site. The Chassahowitzka NWR IMPROVE monitoring site seasonal aerosol data is summarized on Table 10-1. CALPOST was then used to compute

Table 10-1. Chassahowitzka NWR IMPROVE Data 1994 to 1998 10th Percentile

Species	Concentrations (ug/m^3)			
	Winter	Spring	Summer	Autumn
Sulfate (as ammonium sulfate), $(NH_4)_2SO_4$	2.10	2.70	1.80	1.90
Nitrate (as ammonium nitrate), NH_4NO_3	0.31	0.27	0.21	0.19
Organic Carbon, OC	1.30	1.40	1.20	1.30
Soil	0.10	0.26	0.24	0.15
Elemental Carbon, EC	0.28	0.35	0.14	0.26
PM_{10}	10.00	13.00	12.00	12.00
$PM_{2.5}$	5.10	6.70	5.40	5.10
Coarse Particulate Mass, PMC*	4.90	6.30	6.60	6.90

*Estimated as the difference between PM_{10} and $PM_{2.5}$.

Sources: NPS, 2000.
ECT, 2001

background extinction coefficients using the available aerosol data and the IWQAM recommended extinction efficiency for each species.

Similar to the CALPUFF program, the various CALPOST program options are implemented by means of a control file. CALPOST options selected for the Chassahowitzka NWR impact assessments conform to the recommendations contained in the IWQAM Phase 2 report. Background light extinction Method 2 was selected to develop visibility impacts; this method uses monthly data for speciated particulate concentrations and hourly relative humidity data. The current version of CALPOST (Version 5.2, Level 991104B) was used in the Chassahowitzka NWR air quality impact assessments.

10.7 RECEPTOR GRID

Consistent with prior FDEP modeling guidance, the CALPUFF receptor grid consisted of 13 discrete receptors that define the boundary of the Chassahowitzka NWR. Specific modeled receptors are as follows:

Receptor No.	X UTM Coordinate (km)	Y UTM Coordinate (km)	Ground Elevation (m)
1	340.3000	3,165.7000	0.000
2	340.3000	3,167.7000	0.000
3	340.3000	3,169.8000	0.000
4	340.7000	3,171.9000	0.000
5	342.0000	3,174.0000	0.000
6	343.0000	3,176.2000	0.000
7	343.7000	3,178.3000	0.000
8	342.4000	3,180.6000	0.000
9	341.1000	3,183.4000	0.000
10	339.0000	3,183.4000	0.000
11	336.5000	3,183.4000	0.000
12	334.0000	3,183.4000	0.000
13	331.5000	3,183.4000	0.000

Terrain elevations at the coastal Chassahowitzka NWR are well below the MEC CTG stack heights. Accordingly, assignment of receptor terrain elevations was not conducted.

10.8 METEOROLOGICAL DATA

Meteorological data for calendar year 1990 provided as input to the CALMET program consisted of six surface stations, three upper air (mixing height) stations, and 19 precipitation stations. The location (city and county), station identification number, UTM coordinates, and relative locations of the meteorological stations to the Chassahowitzka NWR and HCGF are provided in Table 10-2. The location of each meteorological station is shown on Figure 10-1.

With the exception of the precipitation data, all meteorological data files were provided by the FDEP. Precipitation data for 1990, in TD3240 format, for the 19 stations shown on Table 10-2 were obtained from the National Climatic Data Center (NCDC). The NCDC data was processed using the PXTRACT program included with the CALPUFF Modeling System. PXTRACT is a meteorological preprocessor program which extracts data for stations and time periods from a fixed length, formatted precipitation data file in NCDC TD-3240 format. PXTRACT allows data for a particular model run to be extracted from a larger data file and creates a set of station files that are used as input files to the second-stage precipitation preprocessor program, PMERGE.

The PEMERGE program, which is also included with the CALPUFF Modeling System, was then used to read, process, and reformat the precipitation files created by the PXTRACT program. The output of the PMERGE program is a file (PRECIP.DAT) that is used as input to the CALMET program.

10.9 MODELED EMISSION SOURCES

Modeled emission sources consisted of the one combined-cycle CTG/HRSG unit, two simple-cycle CTGs, and fresh water cooling tower proposed for the MEC. For both the CC CTG/HRSG unit and the SC CTGs, emission rates and stack parameters used in the CALPUFF model reflect Case 9 operating conditions; i.e., 100% load and 35 °F ambient temperature. These operating conditions were selected because they result in the highest emission rates. Specific MEC emission source characteristics used in the CALPUFF modeling assessments are summarized in Table 10-3.

Table 10-2. EPMEC Manatee Energy Center
CALMET Meteorological Stations

City	County	Station No.	UTM Coordinates X (km)	UTM Coordinates Y (km)	Location Relative to Chassahowitzka NWR Distance (km)	Location Relative to Chassahowitzka NWR Direction[1] (o)	Location Relative to MEC Distance (km)	Location Relative to MEC Direction[2] (o)
A. Surface Stations (6)								
Daytona	Volusia	12834	495.1	3,228.1	166.4	71	224.5	41
Ft. Myers	Lee	12835	413.7	2,940.4	246.2	162	133.8	151
Gainesville	Alachua	12816	377.4	3,284.1	116.6	20	228.3	7
Orlando	Orange	12815	469.0	3,146.9	134.3	102	149.6	53
Tampa	Hillsborough	12834	349.2	3,094.2	81.2	172	36.7	0
Vero Beach	Indian River	12843	557.5	3,058.4	248.7	118	208.4	90
B. Upper Air Stations (3)								
Apalachicola	Franklin	12832	110.0	3,296.0	258.0	298	337.7	315
Tampa	Hillsborough	12842	349.2	3,094.2	81.2	172	36.7	0
West Palm Beach	Palm Beach	12844	587.9	2,951.4	335.3	132	261.4	114
C. Precipitation Stations (19)								
Brooksville	Hernando	81048	358.0	3,149.6	32.3	141	92.5	6
Cross City	Dixie	82008	290.3	3,281.8	117.2	336	231.8	345
Daytona	Volusia	82158	494.2	3,227.4	165.3	71	223.4	40
Deland	Volusia	82229	470.8	3,209.7	137.7	75	194.8	39
Dowling Park	Lafayette	82391	283.5	3,348.4	182.1	343	298.2	347
Ft. Myers	Lee	83186	413.7	2,940.4	246.2	162	133.8	151
Gainesville	Alachua	83322	355.4	3,284.2	111.1	9	226.8	2
Inglis	Levy	84273	342.6	3,211.7	37.5	8	154.3	358
Lakeland	Polk	84797	409.9	3,099.2	104.4	136	73.7	56
Lisbon	Lake	85076	423.6	3,193.3	88.0	78	154.9	29
Lynne	Marion	85237	409.3	3,230.3	90.8	52	183.0	19
Orlando	Orange	86628	469.0	3,146.9	134.3	102	149.6	53
Parrish	Manatee	86880	367.0	3,054.4	123.7	166	18.2	100
Saint Leo	Pasco	87851	376.5	3,135.1	55.4	135	82.3	19
St. Petersburg	Pinellas	87886	339.6	3,072.0	102.5	179	17.3	327
Tampa	Hillsborough	88788	349.2	3,094.2	81.2	172	36.7	0
Venice	Sarasota	89176	357.6	2,998.2	177.5	174	59.9	172
Venus	Highlands	89184	467.3	3,001.3	216.4	143	130.9	115
Vero Beach	Indian River	89219	554.3	3,056.5	246.7	119	205.2	90

[1] Vector direction from meteorological station to Chassahowitzka NWR.

[2] Vector direction from meteorological station to MEC.

Sources: FDEP, 2000.
ECT, 2001.
NCDC, 2000.

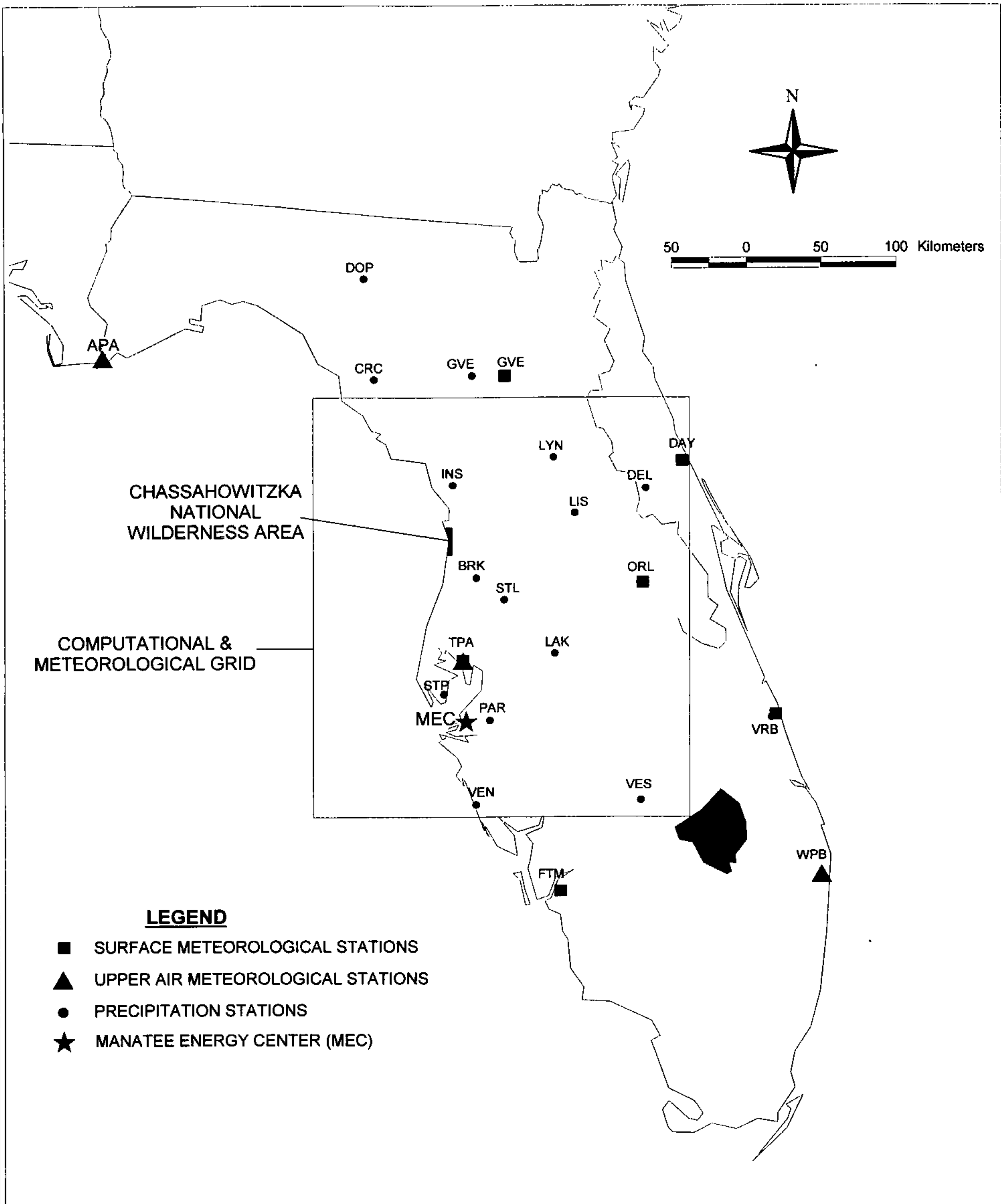

FIGURE 10-1.
CALPUFF METEOROLOGICAL AND COMPUTATIONAL GRID

Sources: FDEP, 2000; NCDC, 2000; ECT, 2001.

elpaso

Table 10-3. MEC CALPUFF Emission Source Data

A. CC CTG/HRSG Case 9 Operating Conditions (i.e., 100-percent load, 35°F)

Parameter	Units	Value
Stack height	ft	135
Stack diameter	ft	19.0
Stack velocity	ft/sec	61.1
Stack temperature	°F	187
SO_2 emissions	lb/hr	7.7
NO_x emissions	lb/hr	23.8
PM_{10} emissions	lb/hr	20.0

B. SC CTGs Case 9 Operating Conditions (i.e., 100-percent load, 35°F)

Parameter	Units	Value (Per CTG)
Stack height	ft	135
Stack diameter	ft	19.0
Stack velocity	ft/sec	146.5
Stack temperature	°F	1,092
SO_2 emissions	lb/hr	7.7
NO_x emissions	lb/hr	61.0
PM_{10} emissions	lb/hr	18.3

Source: ECT, 2001.

10.10 MODEL RESULTS

Refined CALPUFF/CALPOST modeling results for Class I PSD increments, visibility, and deposition impacts at the Chassahowitzka NWR are discussed in the following sections.

10.10.1 PSD CLASS I INCREMENTS

Maximum annual NO_2, SO_2, and PM_{10} impacts are summarized on Table 10-4. Maximum 3- and 24-hour SO_2 impacts are summarized on Table 10-5. Maximum 24-hour PM_{10} impacts are summarized on Table 10-6. These tables provide the highest impact for each pollutant and averaging period, the location of the highest impact, and the time of occurrence for short-term (3- and 24-hour average) impacts.

The critical pollutant and averaging period was determined to be the 24-hour average PM_{10} impact. Maximum MEC 24-hour average PM_{10} impact at the Chassahowitzka NWR is projected to be 0.026 $\mu g/m^3$ or only 8.6 percent of the EPA PSD Class I significant impact level listed in Table 10-6.

The CALPUFF/CALPOST results demonstrate that maximum MEC impacts at the Chassahowitzka NWR will be less than the EPA Class I PSD significant impact levels for all pollutants and averaging periods.

10.10.2 REGIONAL HAZE

Maximum 24-hour regional haze impacts are summarized on Table 10-7. This table provides the emission source beta extinction coefficient, β_{ext}, for each species (SO_4, NO_3, and PMC) as well as the total emission source β_{ext}, background β_{ext} based on the Chassahowitzka NWR IMPROVE speciated aerosol data, background visual range in units of km and dv, and the highest changes in β_{ext} and dv as calculated by the CALPOST program.

The maximum change in β_{ext} is projected to be 0.41 percent, or only 8.2 percent of the NPS significant impact level listed in Table 10-7.

Table 10-4. CALPUFF Model Results - Annual Average Impacts
EPMEC Manatee Energy Center
Chassahowitzka NWR, 1990 Meteorology

Maximum Annual Impacts	NO_2	SO_2	PM_{10}
Modeled Impact ($\mu g/m^3$)	0.00093	0.00052	0.00159
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.2
Exceed PSD Class I Significant Impact (Y/N)	N	N	N
Percent of PSD Significant Impact (%)	0.9	0.5	0.8
Receptor UTM Easting (km)	340.3	340.3	340.3
Receptor UTM Northing (km)	3,165.7	3,165.7	3,165.7
Distance From SC-1 (km)	109	109	109
Direction From SC-1 (Vector °)	355	355	355

Source: ECT, 2001

Table 10-5. CALPUFF Model Results, 3-Hour Average Impacts
EPMEC Manatee Energy Center
Chassahowitzka NWR, 1990 Meteorology

Maximum 3-Hour Impacts	NO_2	SO_2	PM_{10}
Modeled Impact (μg/m^3)	0.133	0.025	0.066
PSD Class I Significant Impact (μg/m^3)	N/A	1.0	N/A
Exceed PSD Significant Impact (Y/N)	N/A	N	N/A
Percent of PSD Significant Impact (%)	N/A	2.5	N/A
Receptor UTM Easting (km)	334.0	340.3	340.3
Receptor UTM Northing (km)	3,183.4	3,165.7	3,165.7
Distance From SC-1 (km)	127	109	109
Direction From SC-1 (Vector °)	353	355	355
Date of Maximum Impact	2/16/90	1/25/90	1/25/90
Starting Hour of Maximum Impact	0200	0500	0500
Julian Date of Maximum Impact	47	25	25

Source: ECT, 2001.

Table 10-6. CALPUFF Model Results, 24-Hour Average Impacts
EPMEC Manatee Energy Center
Chassahowitzka NWR, 1990 Meteorology

Maximum 24-Hour Impacts	NO_2	SO_2	PM_{10}
Modeled Impact (μg/m^3)	0.0459	0.0088	0.0259
PSD Class I Significant Impact (μg/m^3)	N/A	0.2	0.3
Exceed PSD Significant Impact (Y/N)	N/A	N	N
Percent of PSD Significant Impact (%)	N/A	4.4	8.6
Receptor UTM Easting (km)	331.5	340.3	343.7
Receptor UTM Northing (km)	3,183.4	3,165.7	3,178.3
Distance From SC-1 (km)	127	109	121
Direction From SC-1 (Vector °)	352	355	357
Date of Maximum Impact	3/17/90	1/25/90	2/17/90
Julian Date of Maximum Impact	76	25	48

Source: ECT, 2001.

Table 10-7. CALPUFF Model Results, Regional Haze Impacts
EPMEC Manatee Energy Center
Chassahowitzka NWR, 1990 Meteorology

Maximum 24-Hour Average Impacts	Units	Value
B_{ext-s} - SO_4	Mm^{-1}	0.015
B_{ext-s} - NO_3	Mm^{-1}	0.173
B_{ext-s} - PMC	Mm^{-1}	0.015
B_{ext-s} - Total	Mm^{-1}	0.203
B_{ext-b} - Background	Mm^{-1}	49.103
Visual Range, Background	km	79.7
Visual Range, Background	dv	15.9
No. of Days with B_{ext} >5.0 %	-	0.0
Largest B_{ext} change	%	0.41
Date of Largest B_{ext} change	-	1/24/90
NPS Significant Impact, Bext change	%	5.00
Exceed NPS Significant Impact	Y/N	N
Percent of NPS Significant Impact	%	8.2
No. of Days with Delta Deciview >0.5 %	-	0.0
Largest Delta Deciview Change	-	0.041

Note: PMC = particulate mass, coarse.

Source: ECT, 2001.

The CALPUFF/CALPOST results demonstrate that maximum MEC regional haze impacts at the Chassahowitzka NWR will be below the NPS significant impact levels.

10.11 DEPOSITION

Maximum annual sulfur and nitrogen deposition rates are summarized on Table 10-8. This table provides the CALPUFF modeled deposition rates impact for each species (SO_2, SO_4, NO_x, HNO_3, and NO_3) in units of $\mu g/m^2/s$, the conversion factors used to convert the deposition rates from units of $\mu g/m^2/s$ to units of kg/ha/yr, and the total wet and dry sulfur and nitrogen deposition rates.

Maximum MEC total (wet and dry) sulfur and nitrogen deposition rates at the Chassahowitzka NWR are projected to be 0.00075 and 0.00116 kg/ha/yr, respectively. These conservative (i.e., based on continuous operation vs. the maximum 5,000 hours per year operation proposed for the MEC SC CTGs) sulfur and nitrogen deposition rates are only 1.5 and 2.3 percent of the NPS significant impact level of 0.05 kg/ha/yr for sulfur and nitrogen deposition, respectively.

The CALPUFF/CALPOST results demonstrate that maximum MEC sulfur and nitrogen deposition rates at the Chassahowitzka NWR will be below the NPS significant impact levels.

Table 10-8. CALPUFF Model Results, Annual Average Deposition Impacts
EPMEC Manatee Energy Center
Chassahowitzka NWR, 1990 Meteorology

A. Dry Deposition

Maximum Annual Impacts	SO_2	SO_4	NO_x	HNO_3	NO_3	Totals
Modeled Impact ($\mu g/m^2/s$)	1.86E-06	7.89E-09	1.95E-06	4.76E-06	1.80E-08	
Conversions						
MW Ratio (S / SO_2)	0.5000	N/A	N/A	N/A	N/A	
MW Ratio (S / SO_4)	N/A	0.3333	N/A	N/A	N/A	
MW Ratio (N / NO_2)	N/A	N/A	0.3043	N/A	N/A	
MW Ratio (N / HNO_3)	N/A	N/A	N/A	0.2222	N/A	
MW Ratio (N / NO_3)	N/A	N/A	N/A	N/A	0.2258	
ug to kg	1.00E-09	1.00E-09	1.00E-09	1.00E-09	1.00E-09	
m^2 to ha	1.00E+04	1.00E+04	1.00E+04	1.00E+04	1.00E+04	
s to hr	3,600	3,600	3,600	3,600	3,600	
No. of Hours in Averaging Period	8,616	8,616	8,616	8,616	8,616	
Total Multiplier	1.55E+02	1.03E+02	9.44E+01	6.89E+01	7.00E+01	
Sulfur Dry Deposition (kg/ha/yr)	2.88E-04	8.16E-07	N/A	N/A	N/A	2.89E-04
Nitrogen Dry Deposition (kg/ha/yr)	N/A	N/A	1.85E-04	3.28E-04	1.26E-06	5.14E-04

B. Wet Deposition

Maximum Annual Impacts	SO_2	SO_4	NO_x	HNO_3	NO_3	Totals
Modeled Impact ($\mu g/m^2/s$)	2.31E-06	9.86E-07	0.00E+00	5.94E-06	3.39E-06	
Conversions						
MW Ratio (S / SO_2)	0.5000	N/A	N/A	N/A	N/A	
MW Ratio (S / SO_4)	N/A	0.3333	N/A	N/A	N/A	
MW Ratio (N / NO_2)	N/A	N/A	0.3043	N/A	N/A	
MW Ratio (N / HNO_3)	N/A	N/A	N/A	0.2222	N/A	
MW Ratio (N / NO_3)	N/A	N/A	N/A	N/A	0.2258	
ug to kg	1.00E-09	1.00E-09	1.00E-09	1.00E-09	1.00E-09	
m^2 to ha	1.00E+04	1.00E+04	1.00E+04	1.00E+04	1.00E+04	
s to hr	3,600	3,600	3,600	3,600	3,600	
No. of Hours	8,616	8,616	8,616	8,616	8,616	
Total Multiplier	1.55E+02	1.03E+02	9.44E+01	6.89E+01	7.00E+01	
Sulfur Wet Deposition (kg/ha/yr)	3.59E-04	1.02E-04	N/A	N/A	N/A	4.61E-04
Nitrogen Wet Deposition (kg/ha/yr)	N/A	N/A	0.00E+00	4.10E-04	2.38E-04	6.47E-04
Total Dry and Wet Sulfur Deposition (kg/ha/yr)						0.00075
NPS Significance Level (kg/ha/yr)						0.05
Exceed NPS Significance Level (Y/N)						N
Percent of NPS Significance Level (%)						1.5
Total Dry and Wet Nitrogen Deposition (kg/ha/yr)						0.00116
NPS Significance Level (kg/ha/yr)						0.05
Exceed NPS Significance Level (Y/N)						N
Percent of NPS Significance Level (%)						2.3

Y:\GDP-01\ELPASO\MEC\H-10.xls\Deposition--3/7/01

Maximum MEC total (wet and dry) sulfur and nitrogen deposition rates at the Chassahowitzka NWR are projected to be 0.00075 and 0.00116 kg/ha/yr, respectively. These conservative (i.e., based on continuous operation vs. the maximum 5,000 hours per year operation proposed for the MEC SC CTGs) sulfur and nitrogen deposition rates are only 1.5 and 2.3 percent of the NPS significant impact level of 0.05 kg/ha/yr for sulfur and nitrogen deposition, respectively.

The CALPUFF/CALPOST results demonstrate that maximum MEC sulfur and nitrogen deposition rates at the Chassahowitzka NWR will be below the NPS significant impact levels.

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APPENDIX 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: **El Paso Merchant Energy Company**	
2. Site Name: **Manatee Energy Center**	
3. Facility Identification Number: [✔] Unknown	
4. Facility Location: Street Address or Other Locator: **1 Mile N.E. of Buckeye Road and U.S. Highway 41** City: **Piney Point** County: **Manatee** Zip Code: **34221**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [ ] Yes [✔] No

Application Contact

1. Name and Title of Application Contact: **Krish Ravishankar** **Environmental Manager**
2. Application Contact Mailing Address: Organization/Firm: **El Paso Merchant Energy Company** Street Address: **Coastal Tower, Nine Greenway Plaza, Suite 1636** City: **Houston** State: **TX** Zip Code: **77046-0995**
3. Application Contact Telephone Numbers: Telephone: **(713) 877-7023** Fax: **(713) 297-1556**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	3/28/01
2. Permit Number:	0810199-001-AC
3. PSD Number (if applicable):	PSD-FL-318
4. Siting Number (if applicable):	

__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: **William Mack, Senior Managing Director**
2.	Application Contact Mailing Address: Organization/Firm: **El Paso Merchant Energy Company** Street Address: **Coastal Tower, Nine Greenway Plaza, Suite 1682A** City: **Houston** State: **TX** Zip Code: **77046-0995**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(713) 877-3186** Fax: **(713) 297-1641**
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.* [signature] May 23, 01 Signature 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. Owen — Signature

March 6, 2001 — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	CC CTG/HRSG Unit No. 1	AC1A	$7,500
002	SC CTG Unit No. 1	AC1A	N/A
003	SC CTG Unit No. 2	AC1A	N/A
004	Fresh Water Cooling Tower	AC1A	N/A

Application Processing Fee

Check one: [✔] Attached - Amount: $7,500 [ ] Not Applicable

Note: $7,500 application processing fee submitted pursuant to Rule 62-4.050(4)(a)1., F.A.C.

Construction/Modification Information

1. Description of Proposed Project or Alterations:

El Paso Merchant Energy Company (EPMEC) is planning to construct, own, and operate a new electric power generating plant in Manatee County, Florida. The new power plant, designated as the Manatee Energy Center (MEC), will be a natural gas-fired combustion turbine generator (CTG) facility comprised of one combined cycle (CC) CTG with a nominal generating capacity of 250 megawatts (MW), and two simple cycle (SC) CTGs each with a nominal generating capacity of 175 MW. The CC unit will consist of one nominal 175 MW CTG, one unfired heat recovery steam generator (HRSG), and one steam turbine generator (STG) constrained to generate less than 75 MW. Total MEC generating capacity will be a nominal 600 MW. The CTGs will include provisions for inlet air evaporative cooling (simple and combined cycle CTGs) and steam mass flow augmentation (combined cycle CTG). Ancillary emission sources include a fresh water cooling tower and two emergency diesel engines.

The MEC CTGs will be fired exclusively with pipeline-quality natural gas. The CC CTG/HRSG unit will be capable of continuous operation at baseload for up to 8,760 hr/yr. The two SC CTGs will each be capable of continuous operation at baseload for up to 5,000 hr/yr. The CTGs will normally operate between 50- and 100-percent load.

2. Projected or Actual Date of Commencement of Construction: **April 2002**

3. Projected Date of Completion of Construction: **June 2004**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

<table>
<tr><td colspan="4">1. Facility UTM Coordinates:
Zone: 17 East (km): 349.1 North (km): 3,057.6</td></tr>
<tr><td colspan="4">2. Facility Latitude/Longitude:
Latitude (DD/MM/SS): Longitude (DD/MM/SS):</td></tr>
<tr><td>3. Governmental Facility Code:
0</td><td>4. Facility Status Code:
C</td><td>5. Facility Major Group SIC Code:
49</td><td>6. Facility SIC(s):
4911</td></tr>
<tr><td colspan="4">7. Facility Comment (limit to 500 characters):</td></tr>
</table>

Facility Contact

<table>
<tr><td>1. Name and Title of Facility Contact:
To be provided</td></tr>
<tr><td>2. Facility Contact Mailing Address: To be provided
Organization/Firm:
Street Address:
City: State: Zip Code:</td></tr>
<tr><td>3. Facility Contact Telephone Numbers: To be provided
Telephone: Fax:</td></tr>
<tr><td></td></tr>
</table>

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	**B**	**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 combined cycle unit comprised of a nominal 175 MW General Electric (GE) 7FA CTG, one unfired heat recovery steam generator (HRSG), and one steam turbine generator (STG) constrained to generate less that 75 MW. The CTG will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number: [✔] No ID
ID: **001 (CC CTG/HRSG Unit 1)** [ ] 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): **NO_x Controls** **Dry low-NO_x combustors – CTG** **Selective Catalytic Reduction (SCR)**
2. Control Device or Method Code(s): **025 (dry low-NO_x combustors)** **065 (catalytic reduction)**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **175** 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:	**1,742 (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, 35°F. CTG heat input will vary with load, ambient temperature, and optional use of inlet air evaporative cooling and steam mass flow augmentation.**				

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? **CC1**	3. Emission Point Type Code: **1**	
4. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**		
5. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
6. Discharge Type Code: **V**	6. Stack Height: **135** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **192** °F	9. Actual Volumetric Flow Rate: **971,710** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: 17 East (km): **349,029.0** North (km): **3,057,500.3**		
14. Emission Point Comment (limit to 200 characters): **Stack temperature and flow rate are at 100 percent load, 73°F ambient temperature, without inlet air evaporative cooling and steam mass flow augmentation (Case 6). Stack flow rate will vary with load, ambient temperature, and optional use of inlet air evaporative cooling and steam mass flow augmentation.**		

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: **1.787**	5. Maximum Annual Rate: **15,654.1**	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: **23.8** lb/hour **100.9** tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **23.8 lb/hr** Reference: **GE**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 23.0 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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: **23.8** 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: **48.4** lb/hour **206.0** tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **48.4 lb/hr** Reference: **GE**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F ambient temperature and steam mass flow augmentation (Case 14). Annual emissions based on 47.0 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 hr/yr.**		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):		

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **48.4** 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 mass flow augmentation.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: **8.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.0** 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 mass flow augmentation.**	

Allowable Emissions Allowable Emissions ___ of ___

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
5. 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: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **20.0** lb/hour **87.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **20.0 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient (Case 9). Annual emissions based on 20.0 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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: **20.0** 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: **20.0** lb/hour **87.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **20.0 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient (Case 9). Annual emissions based on 20.0 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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: **20.0** 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: **7.7** lb/hour **32.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **7.7 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 (1.787 x 10^6 ft^3/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 7.7 lb/hr SO_2

Annual emissions based on 7.5 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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: **7.7** 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: **1.41** lb/hour **6.0** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.41 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 and 35°F ambient temperature (Case 9). Annual emissions based on 1.37 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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: **1.41** 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: **3.4** lb/hour **14.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **3.4 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F ambient temperature and steam mass flow augmentation (Case 14). Annual emissions based on 3.3 lb/hr (100 percent load, 73°F, evaporative cooling and steam mass flow augmentation – Case 13) for 8,760 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 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **3.4** 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):	

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

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)

<u>Emissions Unit Description and Status</u>

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):
Emission unit consists of one simple cycle unit comprised of a nominal 175-MW General Electric (GE) 7FA CTG. The CTG will be fired exclusively with pipeline quality natural gas.

4. Emissions Unit Identification Number: [✔] No ID [ ] ID Unknown
ID: **001 (SC CTG Unit 1)**

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

7.	Control Equipment/Method Description (Limit to 200 characters per device or method): **NO_x Controls** **Dry low-NO_x combustors – CTG**
8.	Control Device or Method Code(s): **025 (dry low-NO_x combustors)**

Emissions Unit Details

1.	Package Unit: Manufacturer: **General Electric** Model Number: **7FA**
2.	Generator Nameplate Rating: **175 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:	**1,743 (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	
7. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input is lower heating value (LHV) for the CTG at 100 percent load, 35°F. CTG heat input will vary with load, ambient temperature, and optional use of inlet air evaporative cooling.**				

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? **SC1**	9. Emission Point Type Code: **1**	
10. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **N/A**		
11. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **N/A**		
12. Discharge Type Code: **V**	6. Stack Height: **135** feet	7. Exit Diameter: **19.0** feet
8. Exit Temperature: **1,132** °F	9. Actual Volumetric Flow Rate: **2,373,351** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: **17**	East (km): **349,060.4**	North (km): **3,057,545.1**
14. Emission Point Comment (limit to 200 characters): **Stack temperature and flow rate are at 100 percent load, 73°F ambient temperature, without inlet air evaporative cooling (Case 6). Stack flow rate will vary with load, ambient temperature, and optional use of inlet air evaporative cooling.**		

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.**		
3. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million Cubic Feet Burned**	
6. Maximum Hourly Rate: **1.787**	7. Maximum Annual Rate: **8,935.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	10. 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):		
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 – NOX	**025**		**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: **61.0** lb/hour	**143.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: **61.0 lb/hr** Reference: **GE**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 61.0 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 57.0 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 54.0 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
4. Requested Allowable Emissions and Units: **9.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **61.0** 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: **31.0** lb/hour **71.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **31.0 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 31.0 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 28.0 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 27.0 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
6. Requested Allowable Emissions and Units: **8.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **31.0** 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).**	

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: **18.3** lb/hour **45.8** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **18.3 lb/hr** Reference: **GE**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 18.3 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 18.3 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 18.3 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
5. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **18.3** 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: **18.3** lb/hour **45.8** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **18.3 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**

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

Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 18.3 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 18.3 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 18.3 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
6. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **18.3** 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: **7.7** lb/hour	**18.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: **7.7 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 (1.787 x 10^6 ft^3/hr) x (1 lb S/7,000 gr S) x (2 lb SO_2/lb S) = 7.7 lb/hr SO_2

Annual emissions based on 7.7 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 7.2 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 6.8 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
4. Requested Allowable Emissions and Units: **1.5 gr S/100 scf**	4. Equivalent Allowable Emissions: **7.7** 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: **0.94** lb/hour **2.2** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **0.94 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) and 100% conversion of SO_3 to H_2SO_4 for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 0.94 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 0.88 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 0.83 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
4. Requested Allowable Emissions and Units: **1.5 gr S/100 scf**	4. Equivalent Allowable Emissions: **0.94** 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: **3.0** lb/hour **7.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **3.0 lb/hr** Reference: **GE**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load and 35°F ambient temperature (Case 9). Annual emissions based on 3.0 lb/hr (100 percent load, 35°F, – Case 9) for 1,000 hr/yr; 2.8 lb/hr (100 percent load, 73°F, and inlet air evaporative cooling – Case 5) for 3,000 hr/yr; and 2.6 lb/hr (100 percent load, 96°F, and inlet air evaporative cooling – Case 1) for 1,000 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:
4. Requested Allowable Emissions and Units: **1.4 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **3.0** 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):	

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

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __2__

2. 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	
6. Method of Compliance: **EPA Reference Method 9**	
7. 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__

2. 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	
6. Method of Compliance: **EPA Reference Method 9**	
7. 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:
8. 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: $\mathbf{O_2}$	2. Pollutant(s):
3. CMS Requirement:	[✔] Rule [ ] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
8. 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 SC1 and SC2 ARE IDENTICAL UNITS.

SECTION III. EMISSIONS UNIT INFORMATION PROVIDED FOR EU 002 (SC1) IS ALSO APPLICABLE TO EU 003 (SC2).

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):
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: **004 (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): **015**

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: **50,000 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? **CT1 through CT5**		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 five 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: **60** feet	7. Exit Diameter: **40.0** feet
8. Exit Temperature: **100** °F	9. Actual Volumetric Flow Rate: **1,990,513** 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 5 cells with 5 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: **3,000**	5. Maximum Annual Rate: **26,280,000**	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: **0.38** lb/hour **1.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.38 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**

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

(50,000 gal/min) x (0.0005 gal/100 gal) x (3,000 lb PM/10^6 lb water) x (8.345 lb/gal water) x (60 min/hr) = 0.38 lb/hr PM

(0.38 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 1.6 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:
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: **0.23** lb/hour **1.0** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.23 lb/hr** Reference: **AP-42, Section 13.4**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **(50,000 gal/min) x (0.0005 gal/100 gal) x (3,000 lb PM/10^6 lb water) x (0.6 lb PM_{10} / lb PM) x (8.345 lb/gal water) x (60 min/hr) = 0.23 lb/hr PM** **(0.23 lb/hr) x (8,760 hr/yr) x (1 ton/2,000 lb) = 1.0 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

APPENDIX 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)		CC1,SC1 & SC2	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CC1,SC1 & SC2	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CC1,SC1 & SC2	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CC1,SC1 & SC2	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CC1,SC1 & SC2	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	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		CC1,SC1 & SC2	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)	X	CC1,SC1 & SC2	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)		CC1,SC1 & SC2	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CC1,SC1 & SC2	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 MEC CC1 and SC1, SC2 CTGs.
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 MEC CC1 and SC1, SC2 CTGs.

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 MEC CC1 and SC1, SC2 CTGs.
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)		CC1,SC1 & SC2	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		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	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		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to the MEC CC1 and SC1, SC2 CTGs.

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		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CC1,SC1 & SC2	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CC1,SC1 & SC2	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CC1,SC1 & SC2	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CC1,SC1 & SC2	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CC1,SC1 & SC2	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CC1,SC1 & SC2	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CC1,SC1 & SC2	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CC1,SC1 & SC2	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	General missing data requirements.
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CC1,SC1 & SC2	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CC1,SC1 & SC2	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CC1,SC1 & SC2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CC1,SC1 & SC2	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CC1,SC1 & SC2	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CC1,SC1 & SC2	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CC1,SC1 & SC2	General reporting requirements.

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
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CC1,SC1 & SC2	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CC1,SC1 & SC2	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)		CC1,SC1 & SC2	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		CC1,SC1 & SC2	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.

Table 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
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CC1,SC1 & SC2	Requirement for the Designated Representative to hold enough allowances in the appropriate compliance subaccount to cover deductions to be made by EPA if a timely and complete offset plan is not submitted or if EPA disapproves a proposed offset plan **(potential future requirement)**.
Penalties for Excess Emissions of Sulfur Dioxide	§77.6		CC1,SC1 & SC2	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		MEC will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B	X		MEC 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		MEC will not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		MEC will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				

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
Prohibitions	§82.154	X		MEC personnel will not maintain, service, repair, or dispose of any appliances. All such activities will be performed by independent parties in compliance with §82.154 prohibitions.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors will maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152- any device which contains and uses a Class I or II substance as a refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		MEC personnel will not maintain, service, repair, or dispose of any appliances and therefore are not subject to technician certification requirements.

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
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		MEC personnel will not maintain, service, repair, or dispose of any appliances and therefore do not use recovery and recycling equipment.
Reporting and Recordkeeping Requirements	§82.166(k), (m), and (n)		Appliances as defined by §82.152	Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep servicing records documenting the date and type of service, as well as the quantity of refrigerant added.
40 CFR Part 50 - National Primary and Secondary Ambient Air Quality Standards		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 51 - Requirements for Preparation, Adoption, and Submittal of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 52 - Approval and Promulgation of Implementation Plans		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 62 - Approval and Promulgation of State Plans for Designated Facilities and Pollutants		X		State agency requirements - not applicable to individual emission sources.
40 CFR Part 64 - Regulations on Compliance Assurance Monitoring for Major Stationary Sources		X		Exempt per §64.2(b)(1)(iii) since CC1 and SC1, SC2 CTGs 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 MEC.

Source: ECT, 2001.

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 exempted.
Exemptions	62-4.040, F.A.C		X		Certain structural changes exempt from permitting. Other stationary sources exempt from permitting upon FDEP insignificance determination.
Procedures to Obtain Permits	62-4.050, F.A.C.		X		General permitting requirements.
Surveillance Fees	62-4.052, F.A.C.	X			Not applicable to air emission sources.
Permit Processing	62-4.055, F.A.C.	X			Contains no applicable requirements.
Consultation	62-4.060, F.A.C.	X			Consultation is encouraged, not required.
Standards for Issuing or Denying Permits; Issuance; Denial	62-4.070, F.A.C	X			Establishes standard procedures for FDEP. Requirement is not applicable to the MEC CC and SC CTGs.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial contruction permit. Modification of permit conditions is not being requested.
Renewals	62-4.090, F.A.C.		X		Establishes permit renewal criteria. Additional criteria are cited at 62-213.430(3), F.A.C. **(future requirement)**
Suspension and Revocation	62-4.100, F.A.C.		X		Establishes permit suspension and revocation 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.			CC1, SC1 & SC2	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.			CC1, SC1 & SC2	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 MEC CC and SC CTGs.
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 MEC CC and SC CTGs.
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 MEC CC CTG. 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 MEC CC and SC CTGs.

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 MEC.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Project is not located in a nonattainment area or a nonattainment area of influence.

Table 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
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to the MEC CC and SC CTGs.
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.			CC1, SC1 & SC2	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.

Table 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 Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
Permit Issuance, Renewal, and Revision					
Action on Application	62-213.430(1), F.A.C.	X			Contains no applicable requirements.
Permit Denial	62-213.430(2), F.A.C.	X			Contains no applicable requirements.
Permit Renewal	62-213.430(3), F.A.C.		X		Permit renewal application requirements **(future requirement)**.
Permit Revision	62-213.430(4), F.A.C.		X		Permit revision application requirements **(potential future requirement)**.
EPA Recommended Actions	62-213.430(5), F.A.C.	X			Contains no applicable requirements.
Insignificant Emission Units	62-213.430(6), F.A.C.	X			Contains no applicable requirements.
Permit Content	62-213.440, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Review by EPA and Affected States	62-213.450, F.A.C.	X			Agency procedures, contains no applicable requirements.
Permit Shield	62-213.460, F.A.C.		X		Provides permit shield for facilities in compliance with permit terms and conditions. **(future requirement)**
Forms and Instructions	62-213.900, F.A.C.		X		Contains annual emissions fee form requirements.
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.

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
Applicability	§62-214.300, F.A.C.		X		Project includes Acid Rain affected units, therefore compliance with §62-213 and §62-214, F.A.C., is required.
Applications	§62-214.320, F.A.C.			CC1, SC1 & SC2	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.			CC1, SC1 & SC2	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.			CC1, SC1 & SC2	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.			CC1, SC1 & SC2	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.			CC1, SC1 & SC2	Defines permit activation and termination procedures **(potential future requirement)**.

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 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to the MEC.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to the MEC.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to the MEC.
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 MEC.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281, F.A.C.	X			Not applicable to the MEC.

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			MEC 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 MEC.
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			MEC 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		MEC is not located in a specified ozone air quality maintenance area (i.e., is located in Dade, Broward County, or Palm Beach Counties).
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			MEC 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			MEC 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 MEC CC and SC CTGs.
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, 2001.

APPENDIX 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 MEC 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.

APPENDIX A-3

TYPICAL FUEL ANALYSIS

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, 2001.

APPENDIX B

CTG VENDOR DATA

Estimat[illegible]stal - 7FA Performance/Emissions - Combined Cycle GT

ESTIMATE[illegible]RFORMANCE PG7241S(FA)		1	2	3	4	5	[illegible]	7	8	9	10	11	12	13	14
Load Condition		BASE	BASE	75%	50%	BASE	BASE	75%	50%	BASE	75%	50%	BASE	BASE	BASE
Exhaust Pressure Loss	inches Water	14.2	13.6	9.4	6.7	15.6	15.3	10.2	7.2	17.6	11.1	7.7	14.9	16.4	17.3
Ambient Temp.	Deg F.	96	96	96	96	73	73	73	73	35	35	35	96	73	59
Ambient Relative Humid.	%	65	65	65	65	73	73	73	73	73	73	73	65	73	73
Evap. Cooler Status		On	Off	Off	Off	On	Off	Off	Off	Off	Off	Off	On	On	On
Evap. Cooler Effectiveness	%	85				85							85	85	85
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,516	21,515
Fuel Temperature	Deg F	365	365	365	365	365	365	365	365	365	365	365	365	365	365
Output	kW	151,900	146,100	109,600	73,100	163,800	160,700	120,500	80,300	179,500	134,600	89,800	165,100	176,600	182,300
Heat Rate (LHV)	Btu/kWh	9,720	9,820	10,780	12,890	9,495	9,535	10,340	12,390	9,245	9,875	11,880	9,365	9,175	9,090
Heat Cons. (LHV) X 106	Btu/h	1,476.5	1,434.7	1,181.5	942.3	1,555.3	1,532.3	1,246.0	994.9	1,659.5	1,329.2	1,066 8	1,546.2	1,620.3	1,657.1
Exhaust Flow X 103	lb/h	3328	3255	2684	2270	3503	3465	2812	2344	3754	2957	2433	3424	3607	3718
Exhaust Temp.	Deg F.	1153	1162	1194	1200	1134	1138	1173	1200	1096	1144	1195	1141	1118	1099
Exhaust Heat (LHV) X 106	Btu/h	904.2	883.7	763.7	656.7	939.6	928	788.8	683.1	986.4	821.1	720.3	941 2	975.1	992.2
Steam Flow	lb/h	0	0	0	0	0	0	0	0	0	0	0	96950	102130	105300
GT Emissions															
NOX - lb/hr		54	53	43	34	57	56	45	36	61	48	38	71	72	72
CO - lb/hr		27	26	21	18	28	28	23	19	31	24	20	42	43	43
UHC - lb/hr		13	13	11	9	14	14	11	9	15	12	10	14	15	15
SO2 - lb/hr		3	3	2	2	3	3	2	2	3	3	2	3	3	3
SO3 - lb/hr		0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.2
Sulfur Mist - lb/hr		0.3	0.3	0.2	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.2	0.3	0.3	0.3
Total Solid Particulate - lb/hr		9	9	9	9	9	9	9	9	9	9	9	9	9	9
PM10 - lb/hr (front & back half)		18 3	18.3	18.2	18.2	18.3	18.3	18.3	18.2	18.3	18.3	18.2	18 3	18 3	18.3
Estimated Stack Emissions:															
NOX - ppmvd @ 15% O2		3.5	3.5	3 5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.6	4.7	4.7	4.7
NOX - ppmvd		4.3	4.4	4.3	4.0	4.3	4.3	4.2	4.0	4.3	4.3	4.2	6.1	6.0	5.9
NOX - mole/hr		0.458	0.449	0.365	0.288	0.483	0.475	0.382	0.305	0.517	0.407	0.322	0.602	0.610	0.610
NOX - lb/hr		21.1	20.7	16.8	13.3	22.2	21.8	17.6	14.0	23.8	18.7	14.8	27.7	28.1	28.1
CO - ppmvd		9 2	9.0	8.8	8 9	8.9	9.0	9.1	9.0	9.1	9.0	9.3	15.2	15 0	14.9
CO - mole/hr		1.0	0.9	0.8	0.6	1.0	1.0	0.8	0 7	1.1	0.9	0.7	1.5	1.5	1.5
CO - lb/hr		27.0	26.0	21.0	18.0	28.0	28 0	23.0	19 0	31.0	24.0	20.0	42.0	43 0	43.0
UHC - ppmvw		6.9	7.0	7.2	7.0	7.1	7.1	6 9	6.8	7.1	7.2	7.5	7.5	7.9	7 9
UHC - lb/hr		13.0	13.0	11.0	9.0	14.0	14.0	11.0	9 0	15.0	12.0	10 0	14.0	15.0	15.0
VOC - ppmvw		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.6	1.6
VOC - lb/hr		2.6	2.6	2.2	1.8	2.8	2.8	2.2	1.8	3 0	2.4	2.0	2.8	3.0	3.0
SO2 - ppmvw		0 37	0.37	0.37	0.35	0.38	0.38	0.38	0 36	0.38	0.38	0.39	0.40	0 41	0.42
SO2 - lb/hr		2.84	2.76	2.27	1.81	2.99	2.95	2.40	1.91	3.19	2.56	2.05	2.97	3.12	3 19
SO3 - ppmvw		0 03	0.03	0.03	0 03	0.03	0 03	0.03	0 03	0.03	0 03	0.03	0.03	0.03	0.03
SO3 - lb/hr		0 20	0.20	0.16	0.13	0.21	0.21	0.17	0 14	0.23	0 18	0.15	0.21	0.22	0 23
Sulfur Mist - lb/hr		0.30	0.30	0.24	0.19	0.32	0 32	0.26	0 21	0.34	0.27	0.22	0.32	0.33	0.34
PM10 - lb/hr (front & back half)(after SCR's)		20	20	19	19	20	20	19	19	20	19	19	20	20	20
NH3 Slip - lb/hr		11	10	9	7	11	10	9	7	12	11	10	11	11	11
NH3 Slip - ppm		5	5	5	5	5	5	5	5	5	5	5	5	5	5
Exhaust Gas Analysis at Boiler Stack															
Argon	% Vol.	0.870	0.870	0.880	0.880	0.890	0.880	0.890	0.880	0.900	0 890	0.910	0.820	0.840	0.840
Nitrogen	% Vol.	72.203	72.453	72.483	72 653	73.573	73.730	73.733	73.890	74.840	74.810	74 903	68.930	70.230	70.810
Oxygen	% Vol.	12.069	12.179	12.269	12.789	12.389	12.450	12.499	12.910	12.710	12.610	12.909	11.190	11.530	11.720
Cabon Dioxide	% Vol.	3.680	3.660	3.610	3.380	3.700	3.690	3.670	3.480	3.710	3.760	3.620	3.680	3.680	3.670
Water	% Vol.	11.179	10.839	10.759	10.299	9.449	9.250	9.209	8.840	7.840	7.930	7.659	15.380	13.720	12.960
	SUM:	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100 0	100.0	100.0	100 0	100.0	100.0	100 0
Exhaust Products MW		28.07	28.11	28.11	28.14	28.26	28.28	28.29	28.31	28 44	28.43	29.32	29.39	30.45	31.41
Boiler Stack Velocity															
Stack Temperature - F	(Estimated)	197	195	182	174	193	192	177	166	187	169	154	199	195	193
Stack Diameter - ft	(Assumed)	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 Flow Area - sq. ft.		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
Stack Gas Density - lb/ft3		0.05852	0.05876	0.05991	0.06076	0.05929	0.05942	0.06078	0 06188	0.06019	0.06194	0.06540	0.06104	0.06361	0.06582
Exhaust Flow - ACFM		947879	923248	746632	622644	984782	971932	771108	631292	1039473	795670	620059	934979	945039	941491
Stack Exit Velocity - ft/s		55.7	54.3	43.9	36.6	57.9	57.1	45.3	37.1	61.1	46.8	36.4	55.0	55 6	55.3

Assumptions:

Fuel Sulpher content (ppmw)	23.67
SO3/(SO3+SO2)	0.05
NOx SCR Reduction Effectiveness	81%
CO Catalylist Reduction Effectivenes	(NONE)
Stack Diameter (feet)	19

Estimat[illegible]astal - 7FA Performance/Emissions - Simple Cycle GT

ESTIMATED PERFORMANCE PG7241S(FA)		1	2	3	4	[illegible]	6	7	8	9	10	11
Load Condition		BASE	BASE	75%	50%	BASE	BASE	75%	50%	BASE	75%	50%
Exhaust Pressure Loss	inches Water	4.8	4.6	3.1	2.2	5.3	5.2	3.4	2.4	6	3.7	2.6
Ambient Temp.	Deg F.	96	96	96	96	73	73	73	73	35	35	35
Ambient Relative Humid.	%	65	65	65	65	73	73	73	73	73	73	73
Evap. Cooler Status		On	Off	Off	Off	On	Off	Off	Off	Off	Off	Off
Evap. Cooler Effectiveness	%	85				85						
Fuel Type		Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane	Methane
Fuel LHV	Btu/lb	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515	21,515
Fuel Temperature	Deg F	365	365	365	365	365	365	365	365	365	365	365
Output	kW	153,600	147,800	110,800	73,900	165,700	162,600	122,000	81,300	180,700	135,500	90,300
Heat Rate (LHV)	Btu/kWh	9,605	9,695	10,640	12,760	9,385	9,425	10,190	12,260	9,185	9,775	11,760
Heat Cons. (LHV) X 10^6	Btu/h	1,475.3	1,432.9	1,178.9	943.0	1,555.1	1,532.5	1,243.2	996.7	1,659.7	1,324.5	1,061.9
Exhaust Flow X 10^3	lb/h	3328	3255	2682	2262	3503	3465	2805	2337	3754	2949	2436
Exhaust Temp.	Deg F.	1146	1154	1185	1200	1128	1132	1165	1200	1092	1137	1185
Exhaust Heat (LHV) X 10^6	Btu/h	897.3	876.2	757.1	654.7	932.9	921.7	781	681.5	982.6	813.5	713.9
GT EMISSIONS												
NOx	ppmvd @ 15% O2	9	9	9	9	9	9	9	9	9	9	9
NOx AS NO2	lb/h	54	52	43	34	57	56	45	36	61	48	38
CO	ppmvd	9	9	9	9	9	9	9	9	9	9	9
CO	lb/h	27	26	21	18	28	28	23	19	31	24	20
UHC	ppmvw	7	7	7	7	7	7	7	7	7	7	7
UHC	lb/h	13	13	11	9	14	14	11	9	15	12	10
VOC	ppmvw	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC	lb/h	2.6	2.6	2.2	1.8	2.8	2.8	2.2	1.8	3	2.4	2
SO2	ppmvw	0.37	0.37	0.37	0.35	0.38	0.38	0.38	0.36	0.38	0.38	0.38
SO2	lb/h	2.84	2.76	2.27	1.81	2.99	2.95	2.39	1.92	3.19	2.55	2.04
SO3	ppmvw	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
SO3	lb/h	0.20	0.20	0.16	0.13	0.21	0.21	0.17	0.14	0.23	0.18	0.15
Sulfur Mist	lb/h	0.30	0.30	0.24	0.19	0.32	0.32	0.26	0.21	0.34	0.27	0.22
Particulates (PM10 Front & Back Half)	lb/h	18.3	18.3	18.2	18.2	18.3	18.3	18.3	18.2	18.3	18.3	18.2
GT EXHAUST ANALYSIS % VOL.												
Argon		0.88	0.88	0.87	0.87	0.89	0.88	0.89	0.88	0.89	0.89	0.9
Nitrogen		72.21	72.46	72.49	72.65	73.58	73.73	73.74	73.87	74.84	74.81	74.92
Oxygen		12.08	12.19	12.29	12.76	12.39	12.45	12.5	12.88	12.71	12.62	12.95
Carbon Dioxide		3.67	3.65	3.61	3.39	3.7	3.69	3.67	3.5	3.71	3.75	3.6
Water		11.17	10.83	10.75	10.33	9.45	9.25	9.21	8.87	7.85	7.93	7.63
	SUM:	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Exhaust Products MW		28.1	28.1	28.1	28.1	28.3	28.3	28.3	28.3	28.4	28.4	29.3

SITE CONDITIONS

Elevation	ft.	15
Site Pressure	psia	14.69
Inlet Loss	in Water	4
Exhaust Loss	in Water	5.5 @ ISO Conditions
Application		
Combustion System		9/42 DLN Combustor

Assumptions:

Fuel Sulpher content (ppmw)	23.67
SO3/(SO3+SO2)	0.05
NOx SCR Reduction Effectiveness	0%
CO Catalylist Reduction Effectiveness	0%

Emission information based on GE recommended measurement methods. NOx emissions are corrected to 15% O2 without heat rate correction and are not corrected to ISO reference condition per 40CFR 60.335(c)(1). NOx levels shown will be controlled by algorithms within the SPEEDTRONIC control system.

Sulfur Emissions Based On 0.002367 WT% or .2 grains/100 ft^3 Sulfur Content in the Fuel.

IPS- Simple Cycle version code- 2 . 1 . 1 Opt: N 724120300
JACOBSJO 10/24/00 9:51 Coastal - 7FA Emissions - SC.dat

APPENDIX C

EMISSION RATE CALCULATIONS

Table C-1A. EPMEC Manatee Energy Center Operating Scenarios - Combined Cycle Mode

GE Case No.	Ambient Temperature (°F)	Turbine Inlet Temperature (°F)	Load (%)	CTG/HRSG Unit 1	Annual Profile A (hr/yr)	Annual Profile B (hr/yr)	Evaporative Cooling	Steam Mass Flow Augmentation
	Winter							
9	35.0	35.0	100	✔		540		
10	35.0	35.0	75	✔				
11	35.0	35.0	50	✔				
	ISO							
14	59.0	55.0	100	✔		1,620	✔	✔
	Annual Average							
5	73.0	68.0	100	✔			✔	
13	73.0	68.0	100	✔	8,760	4,764	✔	✔
6	73.0	73.0	100	✔				
7	73.0	73.0	75	✔				
8	73.0	73.0	50	✔				
	Summer							
1	96.0	87.0	100	✔			✔	
12	96.0	87.0	100	✔		1,836	✔	✔
2	96.0	96.0	100	✔				
3	96.0	96.0	75	✔				
4	96.0	96.0	50	✔				

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-1B. EPMEC Manatee Energy Center Operating Scenarios - Simple Cycle Mode

GE Case No.	Ambient Temperature (°F)	Turbine Inlet Temperature (°F)	Load (%)	CTG Units 1-2	Annual Profile A (hr/yr)	Annual Profile B (hr/yr)	Evaporative Cooling
	Winter						
9	35.0	35.0	100	✔		1,000	
10	35.0	35.0	75	✔			
11	35.0	35.0	50	✔			
	Annual Average						
5	73.0	68.0	100	✔	5,000	3,000	✔
6	73.0	73.0	100	✔			
7	73.0	73.0	75	✔			
8	73.0	73.0	50	✔			
	Summer						
1	96.0	87.0	100	✔		1,000	✔
2	96.0	96.0	100	✔			
3	96.0	96.0	75	✔			
4	96.0	96.0	50	✔			

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-2A. EPMEC Manatee Energy Center
Combined Cycle Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp. (°F)	GE Case No.	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)
Winter 35	9	100	20.0	2.520	7.7	0.965	1.41	0.177	0.0286	0.00360
	10	75	19.0	2.394	6.1	0.773	1.13	0.142	0.0229	0.00289
	11	50	19.0	2.394	4.9	0.620	0.90	0.114	0.0184	0.00232
59	14	100	20.0	2.520	7.6	0.963	1.41	0.177	0.0285	0.00360
Annual Avg. 73	5	100	20.0	2.520	7.2	0.904	1.32	0.166	0.0268	0.00338
	13	100	20.0	2.520	7.5	0.942	1.37	0.173	0.0279	0.00352
	6	100	20.0	2.520	7.1	0.891	1.30	0.164	0.0264	0.00333
	7	75	19.0	2.394	5.7	0.724	1.06	0.133	0.0215	0.00270
	8	50	19.0	2.394	4.6	0.578	0.84	0.106	0.0171	0.00216
Summer 96	1	100	20.0	2.520	6.8	0.858	1.25	0.158	0.0254	0.00320
	12	100	20.0	2.520	7.1	0.899	1.31	0.165	0.0266	0.00336
	2	100	20.0	2.520	6.6	0.834	1.22	0.153	0.0247	0.00311
	3	75	19.0	2.394	5.5	0.687	1.00	0.126	0.0204	0.00256
	4	50	19.0	2.394	4.3	0.548	0.80	0.101	0.0162	0.00205
		Maximums	**20.0**	**2.520**	**7.7**	**0.965**	**1.41**	**0.177**	**0.0286**	**0.00360**

Amb. Temp. (°F)	GE Case No.	Load (%)	NO_x (ppmvd)[4]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[4]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[4]	VOC (lb/hr)[5]	VOC (g/sec)
Winter 35	9	100	3.5	23.8	2.999	7.6	31.0	3.906	1.3	3.0	0.378
	10	75	3.5	18.7	2.356	7.4	24.0	3.024	1.2	2.4	0.302
	11	50	3.5	14.9	1.879	7.9	20.6	2.591	1.4	2.1	0.259
59	14	100	3.5	23.6	2.968	11.8	48.4	6.103	1.5	3.4	0.430
Annual Avg. 73	5	100	3.5	22.2	2.797	7.3	28.0	3.528	1.3	2.8	0.353
	13	100	3.5	23.0	2.902	11.7	47.0	5.926	1.5	3.3	0.419
	6	100	3.5	21.8	2.747	7.4	28.0	3.528	1.3	2.8	0.353
	7	75	3.5	17.6	2.218	7.5	23.0	2.898	1.3	2.2	0.277
	8	50	3.5	14.0	1.764	7.9	19.0	2.394	1.3	1.8	0.227
Summer 96	1	100	3.5	21.1	2.659	7.4	27.0	3.402	1.3	2.6	0.328
	12	100	3.5	22.0	2.770	11.7	44.7	5.628	1.4	3.0	0.375
	2	100	3.5	20.7	2.608	7.3	26.0	3.276	1.3	2.6	0.328
	3	75	3.5	16.8	2.117	7.3	21.0	2.646	1.3	2.2	0.277
	4	50	3.5	13.3	1.676	7.9	18.0	2.268	1.4	1.8	0.227
		Maximums	**3.5**	**23.8**	**2.999**	**11.8**	**48.4**	**6.103**	**1.5**	**3.4**	**0.430**

[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 (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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-2B. EPMEC Manatee Energy Center
Simple Cycle Hourly Emission Rates (Per CTG/HRSG)
Criteria Air Pollutants and Sulfuric Acid Mist

Amb. Temp. (°F)	GE Case No.	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)
Winter 35	9	100	18.3	2.306	7.7	0.965	0.94	0.118	0.0286	0.00360
	10	75	18.3	2.306	6.1	0.770	0.75	0.094	0.0254	0.00320
	11	50	18.2	2.293	4.9	0.617	0.60	0.076	0.0229	0.00289
Annual Avg. 73	5	100	18.3	2.306	7.2	0.904	0.88	0.111	0.0285	0.00360
	6	100	18.3	2.306	7.1	0.891	0.87	0.109	0.0268	0.00338
	7	75	18.3	2.306	5.7	0.723	0.70	0.089	0.0266	0.00336
	8	50	18.2	2.293	4.6	0.580	0.56	0.071	0.0215	0.00270
Summer 96	1	100	18.3	2.306	6.8	0.858	0.83	0.105	0.0279	0.00352
	2	100	18.3	2.306	6.6	0.833	0.81	0.102	0.0264	0.00333
	3	75	18.2	2.293	5.4	0.685	0.67	0.084	0.0247	0.00311
	4	50	18.2	2.293	4.4	0.548	0.53	0.067	0.0204	0.00256
		Maximums	**18.3**	**2.306**	**7.7**	**0.965**	**0.94**	**0.118**	**0.0286**	**0.00360**

Amb. Temp. (°F)	GE Case No.	Load (%)	NO_x (ppmvd) [4]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd) [4]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd) [4]	VOC (lb/hr) [5]	VOC (g/sec)
Winter 35	9	100	9.0	61.0	7.686	7.5	31.0	3.906	1.3	3.0	0.378
	10	75	9.0	48.0	6.048	7.4	24.0	3.024	1.2	2.4	0.302
	11	50	9.0	38.0	4.788	7.7	20.0	2.520	1.3	2.0	0.252
Annual Avg. 73	5	100	9.0	57.0	7.182	7.4	28.0	3.528	1.3	2.8	0.353
	6	100	9.0	56.0	7.056	7.4	28.0	3.528	1.3	2.8	0.353
	7	75	9.0	45.0	5.670	7.4	23.0	2.898	1.3	2.2	0.277
	8	50	9.0	36.0	4.536	7.8	19.0	2.394	1.3	1.8	0.227
Summer 96	1	100	9.0	54.0	6.804	7.3	27.0	3.402	1.3	2.6	0.328
	2	100	9.0	52.0	6.552	7.3	26.0	3.276	1.3	2.6	0.328
	3	75	9.0	43.0	5.418	7.4	21.0	2.646	1.3	2.2	0.277
	4	50	9.0	34.0	4.284	8.0	18.0	2.268	1.4	1.8	0.227
		Maximums	**9.0**	**61.0**	**7.686**	**8.0**	**31.0**	**3.906**	**1.4**	**3.0**	**0.378**

[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 (CTG) 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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-3A1. EPMEC Manatee Energy Center
Combined Cycle: Hazardous Air Pollutants - Annual Profile A

Parameter	Units	Annual Profile A		
		GE Case 13		
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,871	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/HRSG)				CTG/HRSG 1
		GE Case 13 (lb/hr)			Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001			0.0005	0.0005
Acetaldehyde	4.31E-05	0.081			0.3533	0.35
Acrolein	5.60E-06	0.010			0.0459	0.05
Benzene	1.83E-05	0.034			0.150	0.15
Ethylbenzene	2.28E-05	0.043			0.187	0.19
Formaldehyde	1.14E-04	0.213			0.934	0.93
Mercury	7.80E-10	0.0000015			0.000006	0.000006
Naphthalene	6.33E-07	0.001			0.005	0.005
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001			0.004	0.004
Propylene Oxide	2.86E-05	0.054			0.234	0.234
Toluene	6.80E-05	0.127			0.557	0.557
Xylene	6.51E-05	0.122			0.534	0.534
Maximum Individual HAP		0.213			0.934	0.934
Total HAPs		0.686			3.006	3.006

(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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-3A2. EPMEC Manatee Energy Center
Combined Cycle: Hazardous Air Pollutants - Annual Profile B

Parameter	Units	Annual Profile B			
		Ge Case 9	GE Case 14	GE Case 13	GE Case 12
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,917	1,914	1,871	1,786
Maximum Annual Hours:	hrs/yr	540	1,620	4,764	1,836

Pollutant	Emission Factor [a], [b] (lb/10^6 Btu)	Emission Rates (Per CTG/HRSG)					CTG/HRSG 1 Annual (ton/yr)
		Ge Case 9 (lb/hr)	GE Case 14 (lb/hr)	GE Case 13 (lb/hr)	GE Case 12 (lb/hr)	Annual (ton/yr)	
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0001	0.0005	0.0005
Acetaldehyde	4.31E-05	0.083	0.082	0.081	0.077	0.352	0.35
Acrolein	5.60E-06	0.011	0.011	0.010	0.010	0.046	0.05
Benzene	1.83E-05	0.035	0.035	0.034	0.033	0.149	0.15
Ethylbenzene	2.28E-05	0.044	0.044	0.043	0.041	0.186	0.19
Formaldehyde	1.14E-04	0.219	0.218	0.213	0.204	0.931	0.93
Mercury	7.80E-10	0.0000015	0.0000015	0.0000015	0.0000014	0.0000064	0.000006
Naphthalene	6.33E-07	0.001	0.001	0.001	0.001	0.005	0.005
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.001	0.004	0.004
Propylene Oxide	2.86E-05	0.055	0.055	0.054	0.051	0.234	0.234
Toluene	6.80E-05	0.130	0.130	0.127	0.121	0.555	0.555
Xylene	6.51E-05	0.125	0.125	0.122	0.116	0.532	0.532
Maximum Individual HAP		0.219	0.218	0.213	0.204	0.931	0.931
Total HAPs		0.703	0.702	0.686	0.655	2.994	2.994

[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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-3B1. EPMEC Manatee Energy Center
Simple Cycle: Hazardous Air Pollutants - Annual Profile A

Parameter	Units	Annual Profile A		
		GE Case 5		
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,796	N/A	N/A
Maximum Annual Hours:	hrs/yr	5,000	N/A	N/A

Pollutant	Emission Factor [(a), (b)] ($lb/10^6$ Btu)	Emission Rates (Per CTG)				CTG 1-2
		GE Case 5 (lb/hr)			Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001			0.0003	0.0005
Acetaldehyde	4.31E-05	0.077			0.1935	0.39
Acrolein	5.60E-06	0.010			0.0251	0.05
Benzene	1.83E-05	0.033			0.082	0.16
Ethylbenzene	2.28E-05	0.041			0.102	0.20
Formaldehyde	1.14E-04	0.205			0.512	1.02
Mercury	7.80E-10	0.0000014			0.000004	0.000007
Naphthalene	6.33E-07	0.001			0.003	0.006
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001			0.002	0.004
Propylene Oxide	2.86E-05	0.051			0.128	0.257
Toluene	6.80E-05	0.122			0.305	0.611
Xylene	6.51E-05	0.117			0.292	0.585
Maximum Individual HAP		0.205			0.512	1.024
Total HAPs		0.659			1.646	3.293

[(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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-3B2. EPMEC Manatee Energy Center
Simple Cycle: Hazardous Air Pollutants - Annual Profile B

Parameter	Units	Annual Profile B		
		GE Case 9	GE Case 5	GE Case 1
Maximum CTG Hourly Fuel Flow:	10^6 Btu/hr (HHV)	1,917	1,796	1,704
Maximum Annual Hours:	hrs/yr	1,000	3,000	1000

Pollutant	Emission Factor [(a), (b)] ($lb/10^6$ Btu)	Emission Rates (Per CTG)				CTG 1-2
		GE Case 9 (lb/hr)	GE Case 5 (lb/hr)	GE Case 1 (lb/hr)	Annual (ton/yr)	Annual (ton/yr)
1,3-Butadiene	6.05E-08	0.0001	0.0001	0.0001	0.0003	0.0005
Acetaldehyde	4.31E-05	0.083	0.077	0.073	0.194	0.39
Acrolein	5.60E-06	0.011	0.010	0.010	0.025	0.05
Benzene	1.83E-05	0.035	0.033	0.031	0.082	0.16
Ethylbenzene	2.28E-05	0.044	0.041	0.039	0.103	0.21
Formaldehyde	1.14E-04	0.219	0.205	0.194	0.514	1.03
Mercury	7.80E-10	0.0000015	0.0000014	0.0000013	0.0000035	0.000007
Naphthalene	6.33E-07	0.001	0.001	0.001	0.003	0.006
Polycyclic Aromatic Hydrocarbons	4.71E-07	0.001	0.001	0.001	0.002	0.004
Propylene Oxide	2.86E-05	0.055	0.051	0.049	0.129	0.258
Toluene	6.80E-05	0.130	0.122	0.116	0.306	0.613
Xylene	6.51E-05	0.125	0.117	0.111	0.293	0.587
Maximum Individual HAP		0.219	0.205	0.194	0.514	1.027
Total HAPs		0.703	0.659	0.625	1.652	3.303

[(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: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-3C. EPMEC Manatee Energy Center
Annual Hazardous Air Pollutants Emission Rates

Pollutant	Combined-Cycle Profile A Emissions (ton/yr)	Simple-Cycle Profile B Emissions (ton/yr)	Total Facility Emissions (ton/yr)
1,3-Butadiene	0.0005	0.001	0.0010
Acetaldehyde	0.353	0.388	0.7416
Acrolein	0.046	0.050	0.0964
Benzene	0.150	0.165	0.3149
Ethylbenzene	0.187	0.205	0.3923
Formaldehyde	0.934	1.027	1.9615
Mercury	0.000006	0.000007	0.000013
Naphthalene	0.005	0.006	0.0109
Polycyclic Aromatic Hydrocarbons (PAHs)	0.004	0.004	0.0081
Propylene Oxide	0.234	0.258	0.4921
Toluene	0.557	0.613	1.1700
Xylene	0.534	0.587	1.1201
Maximum Individual HAP	0.934	1.027	1.962
Total HAPs	3.006	3.303	6.309

Sources: ECT, 2001.

Table C-4A1. EPMEC Manatee Energy Center
Combined Cycle Annual Emission Rates - Profile A
Criteria Air Pollutants and Sulfuric Acid Mist

Source	GE Case No.	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	13	1	8,760	23.0	100.9	47.0	206.0	3.3	14.6
		Totals	**8,760**	**N/A**	**100.9**	**N/A**	**206.0**	**N/A**	**14.6**

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	13	1	8,760	20.0	87.6	7.5	32.7	0.028	0.12	1.4	6.0
		Totals	**8,760**	**N/A**	**87.6**	**N/A**	**32.7**	**N/A**	**0.12**	**N/A**	**6.0**

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-4A2. EPMEC Manatee Energy Center
Combined Cycle Annual Emission Rates - Profile B
Criteria Air Pollutants and Sulfuric Acid Mist

Source	GE Case No.	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	9	1	540	23.8	6.4	31.0	8.4	3.0	0.8
CTG/HRSG1	14	1	1,620	23.6	19.1	48.4	39.2	3.4	2.8
CTG/HRSG1	13	1	4,764	23.0	54.9	47.0	112.0	3.3	7.9
CTG/HRSG1	12	1	1,836	22.0	20.2	44.7	41.0	3.0	2.7
		Totals	**8,760**	**N/A**	**100.5**	**N/A**	**200.6**	**N/A**	**14.2**

Source	GE Case No.	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	1	1	540	20.0	5.4	7.7	2.1	0.029	0.01	1.4	0.4
CTG/HRSG1	4	1	1,620	20.0	16.2	7.6	6.2	0.029	0.02	1.4	1.1
CTG/HRSG1	6	1	4,764	20.0	47.6	7.2	17.1	0.027	0.06	1.3	3.1
CTG/HRSG1	11	1	1,836	20.0	18.4	7.1	6.5	0.027	0.02	1.3	1.2
		Totals	**8,760**	**N/A**	**87.6**	**N/A**	**31.9**	**N/A**	**0.12**	**N/A**	**5.9**

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-4B1. EPMEC Manatee Energy Center
Simple Cycle Annual Emission Rates - Profile A
Criteria Air Pollutants and Sulfuric Acid Mist

Source	GE Case No.	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG 1, 2	5	2	5,000	114.0	285.0	56.0	140.0	5.6	14.0
		Totals	**5,000**	**N/A**	**285.0**	**N/A**	**140.0**	**N/A**	**14.0**

Source	GE Case No.	No. of CTGs	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 1, 2	5	2	5,000	36.6	91.5	14.4	35.9	0.057	0.14	1.8	4.4
		Totals	**5,000**	**N/A**	**91.5**	**N/A**	**35.9**	**N/A**	**0.14**	**N/A**	**4.4**

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-4B2. EPMEC Manatee Energy Center
Simple Cycle Annual Emission Rates - Profile B
Criteria Air Pollutants and Sulfuric Acid Mist

Source	GE Case No.	No. of CTGs	Annual Operations (hrs/yr)	Emission Rates					
				NO_x		CO		VOC	
				(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CTG 1, 2	9	2	1,000	122.0	61.0	62.0	31.0	6.0	3.0
CTG 1, 2	5	2	3,000	114.0	171.0	56.0	84.0	5.6	8.4
CTG 1, 2	1	2	1,000	108.0	54.0	54.0	27.0	5.2	2.6
		Totals	**5,000**	**N/A**	**286.0**	**N/A**	**142.0**	**N/A**	**14.0**

Source	GE Case No.	No. of CTGs	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 1, 2	9	2	1,000	36.6	18.3	15.3	7.7	0.06	0.03	1.88	0.9
CTG 1, 2	5	2	3,000	36.6	54.9	14.4	21.5	0.06	0.09	1.76	2.6
CTG 1, 2	1	2	1,000	36.6	18.3	13.6	6.8	0.06	0.03	1.67	0.8
		Totals	**5,000**	**N/A**	**91.5**	**N/A**	**36.0**	**N/A**	**0.1**	**N/A**	**4.4**

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-4C1. EPMEC Manatee Energy Center
Combined Cycle 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	100.9	206.0	14.6	87.6	32.7	0.12	6.0
B	100.5	200.6	14.2	87.6	31.9	0.12	5.9
Maximums	100.9	206.0	14.6	87.6	32.7	0.12	6.0

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-6C2. EPMEC Manatee Energy Center
Simple Cycle 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	285.0	140.0	14.0	91.5	35.9	0.14	4.4
B	286.0	142.0	14.0	91.5	36.0	0.14	4.4
Maximums	286.0	142.0	14.0	91.5	36.0	0.14	4.4

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-4D. EPMEC Manatee Energy Center Annual Criteria Pollutants Emission Rates

Pollutant	Combined-Cycle Profile A Emissions (ton/yr)	Simple-Cycle Profile B Emissions (ton/yr)	Total Facility Emissions (ton/yr)
NO_x	100.9	286.0	386.9
CO	206.0	142.0	348.0
VOC	14.6	14.0	28.6
PM/PM_{10}	87.6	91.5	179.1
SO_2	32.7	36.0	68.7
Pb	0.1	0.1	0.3
H_2SO_4	6.0	4.4	10.4
Totals	447.9	574.0	1,022.0

Source: ECT, 2001.

Table C-5. EPMEC Manatee Energy Center
CTG NSPS Subpart GG Limit (Per CTG)

Fuel	GE 7FA Gas Turbine ISO Heat Rate (LHV)		F	NO_x Std
	(Btu/kw-hr)	(kj/w-hr)		(ppmvd)
Gas	9,370	9.886	0.0	109.2

Sources: ECT, 2001.
GE, 2001.

Table C-6A. EPMEC Manatee Energy Center (Page 1 of 2)
Combined Cycle Exhaust Flow Rates (Per CTG/HRSG)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %													
		100 % Load								75 % Load			50 % Load		
		35 °F	59 °F	73 °F	73 °F	73 °F	96 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
	GE Case No.	9	14	5	13	6	1	12	2	10	7	3	11	8	4
Ar	39.944	0.90	0.84	0.89	0.84	0.88	0.87	0.82	0.87	0.89	0.89	0.88	0.91	0.88	0.88
N_2	28.013	74.84	70.81	73.57	70.23	73.73	72.20	68.93	72.45	74.81	73.73	72.48	74.90	73.89	72.65
O_2	31.999	12.71	11.72	12.39	11.53	12.45	12.07	11.19	12.18	12.61	12.50	12.27	12.91	12.91	12.79
CO_2	44.010	3.71	3.67	3.70	3.68	3.69	3.68	3.68	3.66	3.76	3.67	3.61	3.62	3.48	3.38
H_2O	18.015	7.84	12.96	9.45	13.72	9.25	11.18	15.38	10.84	7.93	9.21	10.76	7.66	8.84	10.30
	Totals	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.44	27.87	28.26	27.79	28.28	28.07	27.61	28.10	28.43	28.28	28.11	28.45	28.31	28.14
Exhaust Flow (lb/sec)		1,042.78	1,032.78	973.06	1,001.94	962.50	924.44	951.11	904.17	821.39	781.11	745.56	675.83	651.11	630.56
Exhaust Temp. (°F)		187	193	193	195	192	197	199	195	169	177	182	154	166	174
(K)		359	363	363	364	362	365	366	364	349	354	356	341	348	352
Ambient Temp (°F)		35	59	73	73	73	96	96	96	35	73	96	35	73	96
(K)		275	288	296	296	296	309	309	309	275	296	309	275	296	309
Exhaust O_2 (Vol %, Dry)		13.79	13.47	13.68	13.36	13.72	13.59	13.22	13.66	13.70	13.77	13.75	13.98	14.16	14.26

B. Exhaust Flow Rates

	100 % Load								75 % Load			50 % Load		
	35 °F	59 °F	73 °F	73 °F	73 °F	96 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	14	5	13	6	1	12	2	10	7	3	11	8	4
ACFM	1,038,914	1,059,546	984,544	1,034,104	971,710	947,506	994,144	922,743	795,740	770,316	745,638	638,674	630,541	622,100
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
Stack Area (ft²)	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)	61.1	62.3	57.9	60.8	57.1	55.7	58.4	54.2	46.8	45.3	43.8	37.5	37.1	36.6
Velocity (m/s)	18.6	19.0	17.6	18.5	17.4	17.0	17.8	16.5	14.3	13.8	13.4	11.4	11.3	11.1
SCFM, Dry[1]	781,271	745,603	720,771	719,142	714,032	676,258	673,933	663,125	614,934	579,642	547,196	507,109	484,769	464,683

[1] At 68 °F.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-6A. EPMEC Manatee Energy Center (Page 2 of 2)
Combined Cycle Exhaust Flow Rates (Per CTG/HRSG)

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

	100 % Load								75 % Load			50 % Load		
	35 °F	59 °F	73 °F	73 °F	73 °F	96 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	14	5	13	6	1	12	2	10	7	3	11	8	4
CO (ppmvd)	9.1	14.9	8.9	15.0	9.0	9.2	15.2	9.0	9.0	9.1	8.8	9.3	9.0	8.9
CO (15% O_2)	7.6	11.8	7.3	11.7	7.4	7.4	11.7	7.3	7.4	7.5	7.3	7.9	7.9	7.9
VOC (ppmvw)	1.4	1.6	1.4	1.6	1.4	1.4	1.5	1.4	1.4	1.4	1.4	1.5	1.4	1.4
VOC (ppmvd)	1.5	1.8	1.5	1.9	1.5	1.6	1.8	1.6	1.5	1.5	1.6	1.6	1.5	1.6
VOC (15% O_2)	1.3	1.5	1.3	1.5	1.3	1.3	1.4	1.3	1.2	1.3	1.3	1.4	1.3	1.4

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-6B. EPMEC Manatee Energy Center (Page 1 of 2)
Simple Cycle Exhaust Flow Rates (Per CTG)

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %										
		100 % Load					75 % Load			50 % Load		
		35 °F	73 °F	73 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
	GE Case No.	9	5	6	1	2	10	7	3	11	8	4
Ar	39.944	0.89	0.89	0.88	0.88	0.88	0.89	0.89	0.87	0.90	0.88	0.87
N_2	28.013	74.84	73.58	73.73	72.21	72.46	74.81	73.74	72.49	74.92	73.87	72.65
O_2	31.999	12.71	12.39	12.45	12.08	12.19	12.62	12.50	12.29	12.95	12.88	12.76
CO_2	44.010	3.71	3.70	3.69	3.67	3.65	3.75	3.67	3.61	3.60	3.50	3.39
H_2O	18.015	7.85	9.45	9.25	11.17	10.83	7.93	9.21	10.75	7.63	8.87	10.33
	Totals	100.00	100.01	100.00	100.01	100.01	100.00	100.01	100.01	100.00	100.00	100.00
Exhaust MW (lb/mole)		28.43	28.26	28.28	28.07	28.11	28.43	28.29	28.11	28.45	28.30	28.14
Exhaust Flow (lb/sec)		1,042.78	973.06	962.50	924.44	904.17	819.17	779.17	745.00	676.67	649.17	628.33
Exhaust Temp. (°F)		1,092	1,128	1,132	1,146	1,154	1,137	1,165	1,185	1,185	1,200	1,200
(K)		862	882	884	892	896	887	903	914	914	922	922
Ambient Temp. (°F)		35	59	73	96	96	35	73	96	35	73	96
(K)		275	288	296	309	309	275	296	309	275	296	309
Exhaust O_2 (Vol %, Dry)		13.79	13.68	13.72	13.60	13.67	13.71	13.77	13.77	14.02	14.13	14.23

B. Exhaust Flow Rates

	100 % Load					75 % Load			50 % Load		
	35 °F	73 °F	73 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	5	6	1	2	10	7	3	11	8	4
ACFM	2,493,042	2,394,771	2,373,351	2,316,528	2,274,153	2,015,604	1,960,647	1,909,518	1,713,802	1,667,656	1,623,863
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
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
Velocity (fps)	146.5	140.8	139.5	136.2	133.7	118.5	115.3	112.2	100.7	98.0	95.5
Velocity (m/s)	44.7	42.9	42.5	41.5	40.7	36.1	35.1	34.2	30.7	29.9	29.1
SCFM, Dry[1]	781,246	720,700	714,032	676,244	663,111	613,297	578,142	546,784	507,896	483,179	462,953

[1] At 68 °F.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-6B. EPMEC Manatee Energy Center (Page 2 of 2)
Simple Cycle Exhaust Flow Rates (Per CTG)

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

	100 % Load					75 % Load			50 % Load		
	35 °F	73 °F	73 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	5	6	1	2	10	7	3	11	8	4
CO (ppmvd)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
CO (15% O_2)	7.5	7.4	7.4	7.3	7.3	7.4	7.4	7.4	7.7	7.8	8.0
VOC (ppmvw)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
VOC (ppmvd)	1.5	1.5	1.5	1.6	1.6	1.5	1.5	1.6	1.5	1.5	1.6
VOC (15% O_2)	1.3	1.3	1.3	1.3	1.3	1.2	1.3	1.3	1.3	1.3	1.4

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-7A. EPMEC Manatee Energy Center
Combined Cycle Hourly Fuel Flow Rates (Per CTG)

	100 % Load								75 % Load			50 % Load		
	35 °F	59 °F	73 °F	73 °F	73 °F	96 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	14	5	13	6	1	12	2	10	7	3	11	8	4
Heat Input - LHV[1] (MMBtu/hr)	1,742	1,740	1,633	1,701	1,609	1,550	1,624	1,506	1,396	1,308	1,241	1,120	1,045	989
Heat Input - HHV[2] (MMBtu/hr)	1,917	1,914	1,796	1,871	1,770	1,705	1,786	1,657	1,535	1,439	1,365	1,232	1,149	1,088
Fuel Rate (lb/hr)	80,989	80,872	75,904	79,076	74,781	72,058	75,459	70,018	64,869	60,809	57,661	52,063	48,554	45,987
Fuel Rate (lb/sec)	22.497	22.464	21.084	21.965	20.773	20.016	20.961	19.449	18.019	16.891	16.017	14.462	13.487	12.774
Fuel Rate[3] (10^6 ft^3/hr)	1.787	1.784	1.675	1.745	1.650	1.590	1.665	1.545	1.431	1.342	1.272	1.149	1.071	1.015

[1] Includes 5.0 % margin.
[2] Based on HHV/LHV ratio of 1.10.
[3] Based on natural gas density of 0.04533 lb/ft^3.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-7B. EPMEC Manatee Energy Center
Simple Cycle Hourly Fuel Flow Rates (Per CTG)

	100 % Load					75 % Load			50 % Load		
	35 °F	73 °F	73 °F	96 °F	96 °F	35 °F	73 °F	96 °F	35 °F	73 °F	96 °F
GE Case No.	9	5	6	1	2	10	7	3	11	8	4
Heat Input - LHV[1] (MMBtu/hr)	1,743	1,633	1,609	1,549	1,505	1,391	1,305	1,238	1,115	1,047	990
Heat Input - HHV[2] (MMBtu/hr)	1,917	1,796	1,770	1,704	1,655	1,530	1,436	1,362	1,226	1,151	1,089
Fuel Rate (lb/hr)	80,999	75,894	74,791	71,999	69,930	64,640	60,672	57,534	51,824	48,642	46,021
Fuel Rate (lb/sec)	22.500	21.082	20.775	20.000	19.425	17.955	16.853	15.982	14.396	13.512	12.784
Fuel Rate[3] (10^6 ft^3/hr)	1.787	1.674	1.650	1.588	1.543	1.426	1.339	1.269	1.143	1.073	1.015

[1] Includes 5.0 % margin.
[2] Based on HHV/LHV ratio of 1.10.
[3] Based on natural gas density of 0.04533 lb/ft^3.

Sources: EPMEC, 2001.
ECT, 2001.
GE, 2001.

Table C-8. EPMEC Manatee Energy Center Facility Annual Emission Rates

Emission Source	Annual Emissions (ton/yr)							
	NO_x	CO	VOC	PM	PM_{10}	SO_2	Pb	H_2SO_4
CTGs	386.88	348.01	28.55	179.10	179.10	68.74	0.26	10.43
Cooling Tower	N/A	N/A	N/A	1.64	0.99	N/A	N/A	N/A
Generator Diesel	3.72	0.83	0.21	0.14	0.14	0.08	Neg.	Neg.
Fire Water Pump Diesel	0.74	0.18	0.08	0.01	0.01	0.01	Neg.	Neg.
Totals	391.34	349.02	28.84	180.90	180.24	68.84	0.26	10.43

Sources: ECT, 2001.
EPMEC, 2001.
General Electric, 2001.

POTENTIAL EMISSION INVENTORY WORKSHEET

EPMEC Manatee Energy Center

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:	2,600 HP 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:	200	hrs/yr
Fuel Flow:	32,370	gal/yr
Fuel Flow:	161.9	gal/hr
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	22.82	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
NO_x	37.24	37.24	3.72
CO	8.34	8.34	0.83
TOC	2.05	2.05	0.21
SO_2	0.820	0.82	0.08
PM	1.380	1.38	0.14
PM_{10}	1.380	1.38	0.14

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	EPMEC, 2001.
Fuel Flow Rate (gal/yr)	ECT, 2001.
Emission Factors (all except TOC)	ECT, 2001.
Emission Factor (TOC)	AP-42, Table 3.4-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	K. Ravishankar	Date:	Feb-01
Data Entered by:	T.Davis	Date:	Feb-01
Reviewed by:	K. Ravishankar	Date:	Feb-01

POTENTIAL EMISSION INVENTORY WORKSHEET

EPMEC Manatee Energy Center

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:	250-HP 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:	200	hrs/yr
Fuel Flow:	3,113	gal/yr
Fuel Flow:	15.6	gal/hr
Diesel Fuel Oil Sulfur Content:	0.05	weight %
Diesel Fuel Oil Heat Content:	141,000	Btu/gal (HHV)
Heat Input:	2.19	MMBtu/hr (HHV)

Criteria Pollutant	Emission Factor (lb/hr)	Potential Emission Rates (lb/hr)	Potential Emission Rates (tpy)
NO_x	7.41	7.41	0.74
CO	1.75	1.75	0.18
TOC	0.79	0.79	0.08
SO_2	0.140	0.14	0.014
PM	0.130	0.13	0.013
PM_{10}	0.130	0.13	0.013

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	EPMEC, 2001.
Fuel Flow Rate (gal/yr)	ECT, 2001.
Emission Factors (all except TOC)	ECT, 2001.
Emission Factor (TOC)	AP-42, Table 3.3-1, EPA, October 1996.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	K. Ravishankar	Date:	Feb-01
Data Entered by:	T.Davis	Date:	Feb-01
Reviewed by:	K. Ravishankar	Date:	Feb-01

POTENTIAL EMISSION INVENTORY WORKSHEET

EPMEC Manatee Energy Center

MAIN-CTW

EMISSION SOURCE TYPE

COOLING TOWERS - PM/PM_{10}

FACILITY AND SOURCE DESCRIPTION

Emission Source Description:	Main Cooling Tower
Emission Control Method(s)/ID No.(s):	Mist Eliminators
Emission Point Description:	Main Cooling Tower, 5 Cell 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:	5	
Recirculating Water Flow Rate:	50,000	gal/min
Drift Loss Rate:	0.0005	%
Total Dissolved Solids (TDS):	3,000	ppmw
PM_{10}/PM Fraction:	0.60	
Number of Towers:	1	

Pollutant	Potential Emission Rates (Per Cell)		Potential Emission Rates (Total)	
	(lb/hr)	(tpy)	(lb/hr)	(tpy)
PM	0.08	0.33	0.38	1.64
PM_{10}	0.05	0.20	0.23	0.99

SOURCES OF INPUT DATA

Parameter	Data Source
Operating Hours (annual)	EPMEC, 2000.
Recirculating Water Flow Rate (gpm)	EPMEC, 2000.
Drift Loss Rate (%)	EPMEC, 2000.
PM_{10}/PM Fraction:	Marley Cooling Tower, 2000.

NOTES AND OBSERVATIONS

DATA CONTROL

Data Collected by:	J. Peter	Feb-01
Data Entered by:	T.Davis	Feb-01
Reviewed by:	K. Ravishankar	Feb-01

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

The AP-42 CT 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 CTs proposed for the EPMEC Manatee Energy Center (MEC) are GE Frame 7FA units each rated at a nominal 175 MW. During natural gas-firing, 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 CTs is not considered applicable to the GE 7FA CT. The GE 7FA CT is 5.7 times larger (i.e., has a rating of 175 vs. 30.6 MW) than the average CT included in the AP-42 CT database and is equipped with DLN and SCR control technology.

Evaluation of the AP-42 CT formaldehyde source test database shows that six of the units tested were large, frame-type CTs. Emission factors for these six CTs were averaged to develop a formaldehyde emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 1.14×10^{-4} lb/10^6 Btu, was used to estimate emissions of formaldehyde for the MEC CTs during natural gas-firing.

A similar analysis was conducted with respect to the April 2000 AP-42 toluene emission factor for natural gas-fired CTs. The April 2000 AP-42 toluene emission factor is based on the average of 7 CT source tests. The CTs in the 7 source test database include small CTs (3 of the 7 CTs tested, or 43% of all units tested, had a rating of less than 15 MW), aircraft-derivative CTs (2 of the 7 CTs, or 29% of all units tested, were GE LM series aircraft-derivative CTs), and frame-type CTs. The largest CT of the 7 units tested was a GE Frame 7 unit with a rating of 75 MW. The average rating of the 7 CTs tested is 26.6 MW. The majority of the CTs tested were equipped with wet (water or steam) injection to control NO_x emissions.

The AP-42 CT test database also shows variability in toluene emission factors. The maximum toluene emission factor (7.10×10^{-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 7 test series include runs for which there were no detectable emissions of toluene.

Evaluation of the AP-42 CT toluene source test database shows that two of the units tested were large, frame-type CTs. Emission factors for these two CTs were averaged to develop a toluene emission factor which is considered to be more representative of the GE 7FA units. This average factor for frame-type CTs, 6.80×10^{-5} lb/10^6 Btu, was used to estimate emissions of toluene for the MEC CTs during natural gas-firing.

Average emission factors for frame-type CTs were developed for the remaining listed HAPs for natural gas-fired CTs using the same methodology as described above for formaldehyde and toluene.

EPMEC MANATEE ENERGY CENTER
EXPLANATION OF APPENDIX C EMISSIONS DATA

Emissions data for the General Electric 7FA combustion turbines (CTs) are provided in Appendix C, Tables 1 through 8. The following sections explain provide the basis for each emission rate calculation.

Note that the calculation results provided in Tables 1 through 8 used full electronic spreadsheet precision; i.e., were not rounded. For this reason, a check of the calculations using the data shown in Tables 1 through 8 may, in some cases, produce slightly different results because the Tables do not display all of the 15 digits used by the electronic spreadsheet.

Tables C-1A and C-1B: Combined- and Simple-Cycle Operating Scenarios

Operating scenarios identified in Tables C-1A and C-1B represent the range of loads (50 to 100 percent) and approximate ambient temperatures (35 to 96°F), fuel type (exclusively natural gas), operating modes (with and without evaporative cooling and steam power augmentation), and annual operating mode profiles under which the combined- and simple-cycle combustion turbines (CTs) will operate.

Tables C-2A and C-2B: Combined- and Simple-Cycle Hourly Emission Rates

A. PM/PM_{10}

For each ambient temperature and CT operating load, PM/PM_{10} emissions in lb/hr were based on GE data for PM/PM_{10} as measured by EPA Reference Methods 201A/202. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Combined-Cycle GE Case 9; 35°F ambient temperature, 100% load

GE PM/PM_{10} = 20.0 lb/hr

PM/PM_{10} = 20.0 lb/hr x 0.126 = 2.520 g/s

B. SO_2

For each ambient temperature and CT operating load, SO_2 emissions in lb/hr were based on GE heat input data, natural gas sulfur content of 1.5 gr S/100 ft^3, natural gas heat content of 21,515 Btu/lb (lower heating value [LHV]), natural gas density of 0.04533 lb/ft^3, and conversion factor of 7,000 grains per pound. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Simple-Cycle GE Case 3; 96°F ambient temperature, 75% load

GE CT heat Input = (1,237.8 x 10^6 Btu/hr) [LHV], with 5% margin

Fuel Flow = (1,237.8 x 10^6 Btu/hr) x (1 lb / 21,515 Btu NG) [LHV]

Fuel Flow = 57,532 lb/hr NG

SO_2 = (57,532 lb/hr NG) x (1.5 gr S / 100 ft^3) x (ft^3 / 0.04533 lb NG)

x (1 lb S / 7,000 gr S) x (2 lb SO_2 / 1 lb S)

SO_2 = 5.4 lb/hr

SO_2 = 5.4 lb/hr x 0.126 = 0.68 g/s

C. H_2SO_4 – Combined-Cycle with SCR

For each ambient temperature and CT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 8.0% conversion rate by volume of SO_2 to SO_3 across the CT, 4.0% conversion rate by volume of SO_2 to SO_3 across the SCR, and 100% conversion by volume of SO_3 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: GE Case No. 14; 59°F ambient temperature, 100% load

SO_2 = 7.6 lb/hr

SO_3 (across CT) = (7.6 lb/hr SO_2) x (8.0 / 100) x (80 lb-mole SO_3 / 64 lb-mole SO_2)

SO_3 (across CT) = 0.76 lb/hr

SO_3 (across SCR) = (7.6 lb/hr SO_2) x (4.0 / 100) x (80 lb-mole SO_3 / 64 lb-mole SO_2)

SO_3 (across SCR) = 0.38 lb/hr

H_2SO_4 = (0.76 lb/hr SO_3 + 0.38 lb/hr SO_3) x (98 lb-mole H_2SO_4 / 80 lb-mole SO_3)

H_2SO_4 = 1.41 lb/hr

H_2SO_4 = 1.41 lb/hr x 0.126 = 0.177 g/s

D. H_2SO_4 – Simple-Cycle

For each ambient temperature and CT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 8.0% conversion rate by volume of SO_2 to SO_3 across the CT and 100% conversion by volume of SO_3 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: GE Case No. 4; 96°F ambient temperature, 50% load

SO_2 = 4.4 lb/hr

SO_3 (across CT) = (4.4 lb/hr SO_2) x (8.0 / 100) x (80 lb-mole SO_3 / 64 lb-mole SO_2)

SO_3 (across CT) = 0.44 lb/hr

H_2SO_4 = (0.44 lb/hr SO_3) x (98 lb-mole H_2SO_4 / 80 lb-mole SO_3)

H_2SO_4 = 0.53 lb/hr

H_2SO_4 = 0.53 lb/hr x 0.126 = 0.067 g/s

E. Lead

For each ambient temperature and CT operating load, estimates of lead emission rates were developed using an emission factor from EPA AP-42 (May 1998 Draft), GE heat input rates, natural gas heat content of 21,515 Btu/lb (lower heating value [LHV]), and natural gas density of 0.04533 lb/ft^3.

Example: Combined-Cycle GE Case No. 1; 96°F ambient temperature, 100% load

GE CT heat Input = (1,550.3 x 10^6 Btu/hr) [LHV], with 5% margin

Fuel Flow = (1,550.3 x 10^6 Btu/hr) x (1 lb / 21,515 Btu NG) [LHV] x (ft^3 / 0.04533 lb NG)

Fuel Flow = 1,5896 x 10^6 ft^3/hr

AP-42 Lead Emission Factor = 0.016 lb / 10^6 ft^3 NG

Lead = (1.5896 x 10^6 ft^3/hr) x (0.016 lb / 10^6 ft^3 NG)

Lead = 0.0254 lb/hr

F. NO_x

For each ambient temperature and CT operating load, NO_x emissions in ppmvd at 15% O_2 and lb/hr were based on GE data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Simple-Cycle GE Case No. 10; 35°F ambient temperature, 75% load

GE NO_x = 9.0 ppmvd @ 15% O_2 GE NO_x = 48.0 lb/hr

NO_x = 48.0 lb/hr

NO_x = 48.0 lb/hr x 0.126 = 6.05 g/s

G. CO

For each ambient temperature and CT operating load, CO emissions in ppmvd at 15% O_2 and lb/hr were based on GE data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Combined-Cycle GE Case No. 7; 73°F ambient temperature, 75% load

GE CO = 9.1 ppmvd @ actual O_2 CO = 7.5 ppmvd @ 15% O_2 GE CO = 23.0 lb/hr

CO = 23.0 lb/hr

CO = 23.0 lb/hr x 0.126 = 2.90 g/s

H. VOC

For each ambient temperature and CT operating load, VOC emissions in ppmvd at 15% O_2 and lb/hr were based on GE data. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Simple-Cycle GE Case No. 2; 96°F ambient temperature, 100% load

GE VOC = 1.4 ppmvw @ actual O_2 VOC = 1.3 ppmvd @ 15% O_2 GE VOC = 2.6 lb/hr

VOC = 2.6 lb/hr

VOC = 2.6 lb/hr x 0.126 = 0.328 g/s

Tables C- 3A1 – C-3B2: Combined- and Simple-Cycle Hourly Emission Rates, Noncriteria Pollutants

Estimates of noncriteria pollutant emission rates were developed using emission factors for frame type CTs > 40 MW from EPA AP-42 and GE heat input data.

EPMEC MANATEE ENERGY CENTER
EXPLANATION OF APPENDIX C EMISSIONS DATA

Example: Simple-Cycle Annual Profile B (GE Case No. 9 for 1,000 hr/yr, GE Case No. 5 for 3,000 hr/yr, and GE Case No. 1 for 1,000 hr/yr), Formaldehyde

Case No. 9:

GE CT heat Input = (1,742.7 x 10^6 Btu/hr) [LHV], with 5% margin

GE CT heat Input = (1,742.7 x 10^6 Btu/hr) [LHV] x 1.10 (HHV/LHV ratio)

GE CT heat Input = (1,917.0 x 10^6 Btu/hr) [HHV]

Formaldehyde Emission Factor = 0.000114 lb / 10^6 Btu [HHV]

Formaldehyde = (1,917.0 x 10^6 Btu/hr) x (0.000114 lb / 10^6 Btu)

Formaldehyde = 0.219 lb/hr

Case No. 5:

GE CT heat Input = (1,632.9 x 10^6 Btu/hr) [LHV], with 5% margin

GE CT heat Input = (1,632.9 x 10^6 Btu/hr) [LHV] x 1.10 (HHV/LHV ratio)

GE CT heat Input = (1,796.1 x 10^6 Btu/hr) [HHV]

Formaldehyde Emission Factor = 0.000114 lb / 10^6 Btu [HHV]

Formaldehyde = (1,796.1 x 10^6 Btu/hr) x (0.000114 lb / 10^6 Btu)

Formaldehyde = 0.205 lb/hr

Case No. 1:

GE CT heat Input = (1,549.1 x 10^6 Btu/hr) [LHV], with 5% margin

GE CT heat Input = (1,549.1 x 10^6 Btu/hr) [LHV] x 1.10 (HHV/LHV ratio)

GE CT heat Input = (1,704.0 x 10^6 Btu/hr) [HHV]

Formaldehyde Emission Factor = 0.000114 lb / 10^6 Btu [HHV]

Formaldehyde = (1,704.0 x 10^6 Btu/hr) x (0.000114 lb / 10^6 Btu)

Formaldehyde = 0.194 lb/hr

Annual Formaldehyde Emission Rate (one CT):

Formaldehyde = [(0.219 lb/hr) x (1,000 hr/yr)] + [(0.205 lb/hr) x (3,000 hr/yr)]
+ [(0.194 lb/hr) x (1,000 hr/yr)]

Formaldehyde = 1,028.0 lb/yr, 0.514 ton/yr

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EXPLANATION OF APPENDIX C EMISSIONS DATA

Annual Formaldehyde Emission Rate (two CTs):

Formaldehyde = (0.514 ton/yr/CT) x (2 CTs)

Formaldehyde = 1.03 ton/yr

Table C-3C: Combined- and Simple-Cycle Hourly Emission Rates, Noncriteria Pollutants

The highest annual profiles for the combined- and simple-cycle modes were summed to develop facility-wide estimates of annual noncriteria pollutant emission rates.

Example: Annual Formaldehyde; Combined-Cycle (Profile A) and Simple-Cycle (Profile B)

Combined-Cycle Profile A:

Formaldehyde = 0.93 ton/yr

Simple-Cycle Profile B:

Formaldehyde = 1.03 ton/yr

Total Facility:

Formaldehyde = (0.93 ton/yr) + (1.03 ton/yr)

Formaldehyde = 1.96 ton/yr

Tables C- 4A1 – C-4B2: Combined- and Simple-Cycle Hourly Emission Rates, Criteria Pollutants

Estimates of criteria pollutant annual emission rates were developed using GE data.

Example: Simple-Cycle Annual Profile B (GE Case No. 9 for 1,000 hr/yr, GE Case No. 5 for 3,000 hr/yr, and GE Case No. 1 for 1,000 hr/yr), NO_x

Case No. 9:

NO_x = 61.0 lb/hr

Case No. 5:

NO_x = 57.0 lb/hr

Case No. 1:

NO_x = 54.0 lb/hr

Annual NO_x Emission Rate (one CT):

NO_x = [(61.0 lb/hr) x (1,000 hr/yr)] + [(57.0 lb/hr) x (3,000 hr/yr)]
+ [(54.0 lb/hr) x (1,000 hr/yr)]

NO_x = 286,000 lb/yr, 143.0 ton/yr

Annual NO_x Emission Rate (two CTs):

NO_x = (143.0 ton/yr/CT) x (2 CTs)

NO_x = 286.0 ton/yr

Table C-4D: Combined- and Simple-Cycle Hourly Emission Rates, Criteria Pollutants

The highest annual profiles for the combined- and simple-cycle modes were summed to develop facility-wide estimates of annual criteria pollutant emission rates.

Example: Annual NO_x; Combined-Cycle (Profile A) and Simple-Cycle (Profile B)

Combined-Cycle Profile A:

NO_x = 100.9 ton/yr

Simple-Cycle Profile B:

NO_x = 286.0 ton/yr

Total Facility:

NO_x = (100.9 ton/yr) + (286.0 ton/yr)

NO_x = 386.9 ton/yr

Table C5: NSPS Subpart GG NO_x Limits

NSPS Subpart GG NO_x limits were calculated based on the GE heat rate at ISO conditions (59°F, 100% load) and the NSPS Subpart GG NO_x limit equation. The GE heat rate was provided on a LHV basis (consistent with the NSPS Subpart GG NOx limit equation) and converted to the appropriate units (i.e., kJ/w-hr).

Example: Natural Gas Combustion

GE Heat Rate at ISO Conditions: 9,370 Btu/kW-hr (LHV)
Heat Rate at ISO Conditions = [9,370 Btu/kW-hr (LHV)] x (1.055056 / 1000)
Heat Rate at ISO Conditions = 9.886 kJ/w-hr

NSPS Subpart GG NO_x Limit = [0.0075 x (14.4 / Heat Rate) + FBN] x 10,000
NSPS Subpart GG NO_x Limit = [0.0075 x (14.4 / 9.886) + 0] x 10,000
NSPS Subpart GG NO_x Limit = 109.2 ppmvd

where FBN = fuel bound nitrogen content of fuel
10,000 = conversion factor for converting volume % to ppmvd

Tables C-6A – C-6B: Combined- and Simple-Cycle Exhaust Data

Exhaust gas compositions (volume %), exhaust flow rates (lb/hr), and exhaust temperatures (°F) shown in Tables C-6A through C-6B were obtained from the GE performance specification data.

EPMEC MANATEE ENERGY CENTER
EXPLANATION OF APPENDIX C EMISSIONS DATA

1. Exhaust gas molecular weight was calculated by multiplying the exhaust composition (in volume % divided by 100) by the component molecular weight (in lb/lb-mole) and summing all components.

Example: Combined-Cycle GE Case No. 10 (35°F, 75% Load)

MW = [(0.89/100) x 39.944] + [(74.81/100) x 28.013] + [(12.61/100) x 31.999]
+ [(3.76/100) x 44.010] + [(7.93/100) x 18.015]

MW = 28.43 lb/lb-mole

2. Exhaust flow rates (in units of lb/sec) were calculated by converting the GE exhaust flow rates (in units of lb/hr).

Example: Simple-Cycle GE Case No. 1 (96°F, 100% Load)

GE Exhaust Flow Rate: 3,328,000 lb/hr

Exhaust Flow Rate = (3,328,000 lb/hr) x (hr / 3,600 sec)
Exhaust Flow Rate = 924.44 lb/sec

3. Exhaust temperatures (in units K) were calculated by converting the GE exhaust temperatures (in units of °F)

Example: Combined-Cycle GE Case No. 14 (59°F, 100% Load)

GE Exhaust Temperature: 193 °F

Exhaust Temperature = (193 °F + 459.67) / (1.8)
Exhaust Temperature = 362.6 K

4. Exhaust oxygen concentrations, dry were calculated by correcting the GE exhaust oxygen concentrations, wet, to dry conditions.

Example: Simple-Cycle GE Case No. 5 (73°F, 100% Load)

GE Exhaust Oxygen Concentration: 12.39 volume % (wet)
GE Exhaust Water Concentration: 9.45 volume %

Exhaust Oxygen Concentration (dry) = [(12.39) / (100 – 9.45)] x 100
Exhaust Oxygen Concentration = 13.68 volume % (dry)

5. Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the GE data shown in Tables C-6A and C-6B. Stack diameter was provided by EPMEC. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

   Exhaust gas flow rates, in units of actual cubic feet per minute, were calculated based on the GE exhaust flow rates (in units of lb/sec) and molecular weights shown in Tables C-6A and C-6B and the Ideal Gas Law.

Example: Combined-Cycle GE Case No. 13 (73°F, 100% Load)

GE Exhaust Flow Rate: 1,001.94 lb/sec (from Table C-6A)
Exhaust Gas Molecular Weight: 27.79 lb/lb-mole (From Table C-6A)
GE Exhaust Gas Temperature: 195 °F (From Table C-6A)
Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (1,001.94 lb/sec) x (60 sec / min) x (lb-mole / 27.79 lb) x (385.3 ft^3/lb-mole) x [(195 + 459.67) / (68 + 459.67)]

Exhaust Gas Flow Rate = 1,034,104 acfm

6. Stack area was calculated based on the stack exit diameter provided by EPMEC.

Example: All Cases

Stack Exit Diameter: 19.0 ft; 5.79 m

Stack Exit Area = π x $(19.0 \text{ ft} / 2)^2$
Stack Exit Area = 283.5 ft^2; 35.8 m^2

7. Stack exit velocities were calculated by dividing the calculated actual exhaust flow rate by the stack exit area.

Example: Simple-Cycle GE Case No. 3 (96°F, 75% Load)

Calculated Actual Exhaust Flow Rate: 1,909,518 ft^3/min (From Table C-6B)
Calculated Stack Exit Area: 283.5 ft^2

Stack Exit Velocity = (1,909,518 ft^3/min) x (1 min / 60 sec) x (1 / 283.5 ft^2)
Stack Exit Velocity = 112.2 ft/sec; 34.2 m/sec

8. Exhaust gas flow rates, in units of dry, standard (at 68 °F) actual cubic feet per minute, were calculated based on the GE exhaust flow rates (in units of lb/sec), moisture contents, and molecular weights shown in Tables C-6A and C-6B and the Ideal Gas Law.

Example: Combined-Cycle GE Case No. 7 (73°F, 75% Load)

GE Exhaust Flow Rate: 781.11 lb/sec (from Table C-6A)
GE Exhaust Gas Moisture Content: 9.21 volume % (from Table C-6A)
Exhaust Gas Molecular Weight: 28.28 lb/lb-mole (From Table C-6A)
Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (781.11 lb/sec) x (60 sec / min) x (lb-mole / 28.28 lb) x (385.3 ft^3/lb-mole) x [1 - (9.21 / 100)]

Exhaust Gas Flow Rate = 579,642 dscfm

9. Exhaust CO concentrations provided by GE (in units of ppmvd) and exhaust VOC concentrations provided by GE (in units of ppmvw) were corrected to dry, 15% O_2 conditions using the calculated dry oxygen contents shown in Tables C-6A and C-6B .

Example: CO, Simple-Cycle GE Case No. 4 (96°F, 50% Load)

GE CO Exhaust Concentration: 9.0 ppmvd
Calculated Exhaust Oxygen Content: 14.23 volume % (dry)
Atmospheric Oxygen Content: 20.9 volume %

Exhaust CO Concentration (ppmvd @ 15% O_2) = (9.0 ppmvd) x [(20.9 – 15.0) / (20.9 – 14.23)]
Exhaust CO Concentration = 8.0 ppmvd @ 15% O_2

Example: VOC, Combined-Cycle GE Case No. 7 (73°F, 75% Load)

GE VOC Exhaust Concentration: 1.4 ppmvw
GE Exhaust Moisture Content: 9.21 volume %
Calculated Exhaust Oxygen Content: 13.77 volume % (dry)
Atmospheric Oxygen Content: 20.9 volume %

Exhaust VOC Concentration (ppmvd) = (1.4 ppmvw) / [1 - (9.21 / 100)]
Exhaust VOC Concentration = 1.5 ppmvd

Exhaust VOC Concentration (ppmvd @ 15% O_2) = (1.5 ppmvd) x [(20.9 – 15.0) / (20.9 – 13.77)]
Exhaust VOC Concentration = 1.3 ppmvd @ 15% O_2

Tables C-7A and C-7B: Fuel Flow Rate

Data shown in Tables C-7A and C-7B is based on GE heat input data and the heat contents and densities of natural gas.

Example: Simple-Cycle GE Case No. 5 (73°F, 100% load)

GE CT heat Input = (1,632.9 x 10^6 Btu/hr) [LHV], with 5% margin
Natural Gas Heat Content: 21,515 Btu/lb (LHV)
Natural Gas Density: 0.04533 lb/ft^3

Fuel Flow Rate (lb/hr) = (1,632.9 x 10^6 Btu/hr) / (21,515 Btu/lb)
Fuel Flow Rate = 75,894 lb/hr

Fuel Flow Rate (10^6 ft^3/hr) = [(75,894 lb/hr) / (0.04533 lb/ft^3)] x 10^{-6}
Fuel Flow Rate = 1.674 x 10^6 ft^3/hr

Table C-8: Facility Annual Emission Rates

Data shown in Table C-8 provides annual emission rates for the MEC CTGs, cooling tower, and diesel engines.

APPENDIX D

CONTROL TECHNOLOGY VENDOR QUOTES

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830

ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail fred.booth@engelhard.com

DATE:	**December 19, 2000**	**NO. PAGES**	**4**
TO:	**ECT**	**via e-mail**	
ATTN:	**Tom Davis**		
	ENGELHARD		
ATTN:	**Nancy Ellison**		
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **Coastal Power**
CO Oxidation System Components
SCR Catalyst System Components
Engelhard Budgetary Proposal EPB00153

We provide Engelhard Proposal EPB00153 for Engelhard **Camet®** metal substrate CO oxidation and Engelhard **NOxCAT VNX™** vanadia-titania (Combined Cycle) and **NOxCAT ZNX™** zeolite (Simple Cycle) SCR Catalyst modules per your e-mail request of December 15, 2000.

r Proposal is based on:

- Given data for GE 7FA Gas Turbine operating in combined and simple cycle modes;
- CO Catalysts for 90% CO Reduction;
- For the simple cycle system we have selected the CO Catalyst at the same cross section as for the SCR Catalysts. This will provide additional flow straightening prior to the AIG.
- SCR Catalysts for NOx reduction noted inlet levels to 3.5 ppmvd @ 15% O_2 with ammonia slip of 10 ppmvd @ 15% O_2;
- The simple cycle SCR catalyst design incorporates Engelhard **NOxCAT ZNX™** with an ambient air cooling system.
- Scope as noted. Please note that we have assumed horizontal gas flow through the CO and SCR reactors;
- Assumed 19% aqueous ammonia;
- For the combined cycle system, we assume HRSG inside liner dimensions of 67 ft H x 26 ft W.
- For the simple cycle system we indicate cross sectional area required to meet the conversions and pressure drops noted. Inside liner width and height can be varied while maintaining same cross sectional area.
- Three (3) Year Performance Guarantee;

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 - Coastal Power
CO Oxidation System Components
SCR Catalyst System Components
Engelhard Budgetary Proposal EPB00153
December 19, 2000

ENGELHARD CORPORATION
CAMET® CO OXIDATION SYSTEMS
NOxCAT SCR NOx ABATEMENT CATALYST SYSTEMS

Scope of Supply: The equipment supplied is installed by others in accordance with the Engelhard design and installation instructions.

- Engelhard **CAMET®** CO Oxidation Catalyst Modules;
- Engelhard **NOxCAT VNX™** and **NOxCAT ZNX™** SCR catalyst in modules;
- Design of Internal support structures for catalyst modules (frame). Frame design allows adding one more layer.
- Review of AIG design;
- Technical Service during installation and Start-Up;

Excluded from Scope of Supply:
Ammonia storage and pumping
Ammonia distribution components
Any internally insulated reactor ductwork to house catalysts
Any transitions to and from reactor
Any monorails and hoists for handling modules
Electrical grounding equipment
Foundations
All other items not specifically listed in Scope of Supply
Ambient air cooling system
Structural support
Any interconnecting field piping or wiring
Utilities
All Monitors

PRICES: fob, plant gate, job site **See Below**

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

DOCUMENT / MATERIAL DELIVERY SCHEDULE
Drawings / Documentation – 2-3 weeks after notice to proceed and Engelhard receipt of all engineering specifications and details
Material Delivery

CO Modules	20 - 24 weeks after approval and release for fabrication
SCR Modules	24 - 28 weeks after approval and release for fabrication

CO and SCR SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7FA Combustion Turbines (Combined and Simple Cycle)
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data
Temperature (At catalyst face):	See Performance data
CO Concentration (At catalyst face):	See Performance Data
CO Reduction:	90%
CO Pressure Drop:	See Performance data
NOx Concentration (At catalyst face):	See Performance data
NOx Reduction:	To 3.5 ppmvd @ 15% O_2
NH3 Slip:	10 ppmvd@15%O_2

ENGELHARD

ECT - Coastal Power
CO Oxidation System Components
SCR Catalyst System Components
Engelhard Budgetary Proposal EPB00153
December 19, 2000

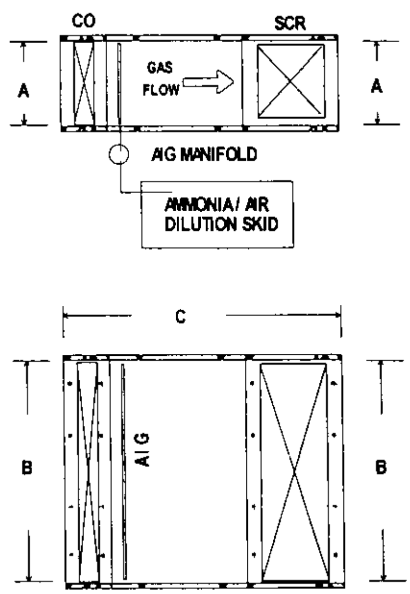
Combined Cycle

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	GE 7FA
TOTAL GAS FLOW AFTER BURNER, lb/hr	3,754,008
	1042.78
GAS ANALYSIS AFTER BURNER, % VOL. N_2	67.04
O_2	12.91
CO_2	3.76
H_2O	15.38
Ar	0.91
CALC. GAS MOL. WT. AFTER BURNER	27.70
GIVEN CO AFTER BURNER, ppmvd @ 15% O_2	11.8
CALC. CO AFTER BURNER, lb/hr	36.2
GIVEN NOx AFTER BURNER, ppmvd @ 15% O_2	12.1
CALC NOx AFTER BURNER, lb/hr	61.0
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650
DESIGN REQUIREMENTS	
CO CATALYST CO OUT, ppmvd @ 15% O_2	1.2
SCR CATALYST NOx OUT, ppmvd @ 15% O_2	3.5
NH_3 SLIP, ppmvd @ 15% O_2	10
GUARANTEED PERFORMANCE DATA	
CO CATALYST CO CONVERSION, % - Min.	90.0%
CO OUT, lb/hr - Max.	3.6
CO OUT, ppmvd @ 15% O_2 - Max.	1.2
CO PRESSURE DROP, "WG - Max.	1.1
SCR CATALYST NOx CONVERSION, % - Min.	71.1%
NOx OUT, lb/hr - Max.	17.7
NOx OUT, ppmvd @ 15% O_2 - Max.	3.5
EXP. AQUEOUS NH_3 (19% SOL.) FLOW, lb/hr	182.5
NH_3 SLIP, ppmvd @ 15% O_2 - Max.	10
SCR PRESSURE DROP, "WG - Max.	1.5
CO SYSTEM	**$703,000**
REPLACEMENT CO CATALYST MODULES	**$624,000**
SCR SYSTEM	**$1,088,000**
REPLACEMENT SCR CATALYST MODULES	**$625,000**

Dimensions:

Inside Liner Width	**(A) 26 ft**
Inside Liner Height	**(B) 67 ft**
Reactor Depth	**(C) 16 ft**



ENGELHARD

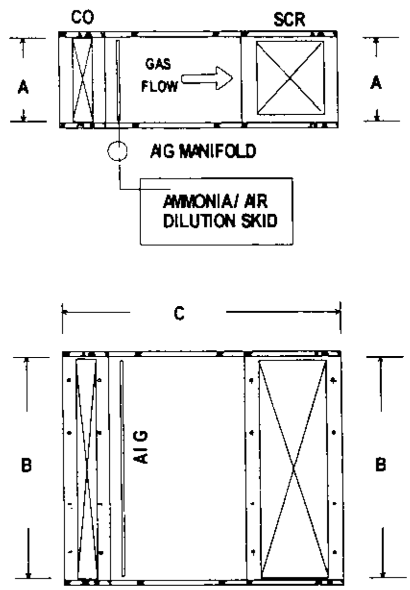
ECT - Coastal Power
CO Oxidation System Components
SCR Catalyst System Components
Engelhard Budgetary Proposal EPB00153
December 19, 2000

Simple Cycle

Performance Data and Budget Pricing

GIVEN / CALCULATED DATA	
AMBIENT	96
TURBINE EXHAUST FLOW, lb/hr	3,754,000
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	71.23
O2	12.95
CO2	3.75
H2O	11.17
Ar	0.90
GIVEN: TURBINE CO, ppmvd @ 15% O2	8
CALC.: TURBINE CO, lb/hr	28.5
GIVEN: TURBINE NOx, ppmvd @ 15%O2	9
CALC.: TURBINE NOx, lb/hr	52.6
GAS TEMP. FROM TURBINE	1200
AMBIENT AIR FLOW-lb/hr	768,778
GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	1025
TOTAL AIR + GAS FLOW, lb/hr	4,522,778
AIR + GAS COMPOSITION - % VOL. N2	72.89
O2	13.92
CO2	3.12
H2O	9.31
AR	0.75
AIR + GAS - MOL WT	28.23
CO AT CO CATALYST -PPMVD-15%O2	7.4
NOx AT SCR CATALYST -PPMVD-15%O2	8.4
DESIGN REQUIREMENTS	
CO CATALYST CO OUT, ppmvd @ 15% O2	0.7
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.3
NH3 SLIP, ppmvd @ 15% O2	10
GUARANTEED PERFORMANCE DATA	
CO CATALYST CO CONVERSION, % - Min.	90.0%
CO OUT, lb/hr - Max.	2.8
CO OUT, ppmvd @ 15% O2 - Max.	0.7
CO PRESSURE DROP, "WG - Max.	1.3
SCR CATALYST NOx CONVERSION, % - Min.	61.1%
NOx OUT, lb/hr - Max.	20.5
NOx OUT, ppmvd @ 15% O2 - Max.	3.3
EXP. AQUEOUS NH3 (19% SOL.) FLOW, lb/hr	202.6
NH3 SLIP, ppmvd @ 15% O2 - Max.	10
SCR PRESSURE DROP, "WG - Max.	4.5
CO SYSTEM	**$1,053,000**
REPLACEMENT CO CATALYST MODULES	**$812,000**
SCR SYSTEM	**$3,027,000**
REPLACEMENT SCR CATALYST MODULES	**$2,113,000**

Dimensions:
Reactor Cross Section:
Inside Liner Width (A) x
Inside Liner Height (B) 2570sq ft
Reactor Depth (C) 16 ft



Received via e-mail on February 6, 2001

Dear Mr. Davis,

Re: Coastal Power Company
Florida Power Projects
General Electric 7FA CTs

In response to your attached request, please note the following budgetary information for a SCONOx(superscript: TM) system on a General Electric 7FA combustion turbine, operating in a combined cycle arrangement. The system is designed to control NOx from 12.1 ppm to 2.0 ppm, and to control CO from 11.8 ppm to 1.2 ppm, at the maximum design condition provided, with the unit firing exclusively on natural gas.

The budgetary capital cost, based on the present pricing level of platinum, for a SCONOx system as specified is $16,300,000 U.S. Alstom also offers a leasing program whereby the SCONOx™ reactor and all mechanical equipment is purchased, but the catalyst is leased under a ten year lease agreement. The lease agreement includes the supply of the catalyst, the washing and maintenance of the catalyst to maintain NOx reduction performance, and the maintenance of the SCONOx™ equipment.

The budgetary initial equipment cost with the lease program is $6,560,000 U.S., and the annual lease payment is $3,500,000 to 4,000,000, pending final determination of scope and lease terms.

Please contact me at 865/694-5242 or Ron Bevan at 215/702-3011 if you have any questions.

Sincerely,

Rick Oegema

APPENDIX E

FDEP CORRESPONDENCE REGARDING FLORIDA POWER PLANT SITING ACT APPLICABILITY

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

August 25, 2000

David M. Sims
Regional Managing Director
Coastal Power Company
Coastal Tower
Nine Greenway Plaza
Houston, Texas 77046-0995

Dear Mr. Sims:

I have reviewed the combined cycle power plant configuration attached to your letter of August 23, 2000. Such a power plant could be exempt from the provisions of the Florida Electrical Power Plant Siting Act provided the steam turbine capacity is limited or restricted to less than 75 megawatts gross capacity. Since the configurations shown have the ability to equal or exceed 75 MW, any permit application to the department will have to include description of engineering devices to limit the steam delivery to the steam turbine. Additionally, the department will require the monitoring of the electric generation rate on a rolling hourly average to demonstrate that 75 MW is not equaled or exceeded.

Sincerely,

Hamilton S. Oven

Hamilton S. oven, P.E.
Administrator, Siting
Coordination Office

Cc: Scott Goorland
Clair Fancy
Al Linero

APPENDIX F

DISPERSION MODELING FILES