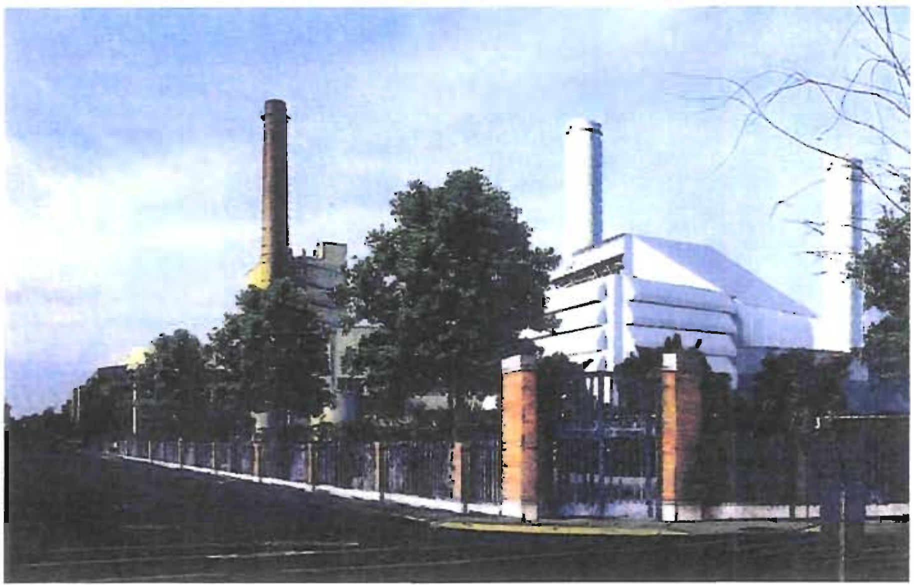
J.R. KELLY GENERATING STATION REPOWERING PROJECT

APPLICATION FOR AIR CONSTRUCTION PERMIT AND TITLE V AIR OPERATION PERMIT REVISION



Prepared for:

GRU
GAINESVILLE REGIONAL UTILITIES
Gainesville, Florida

Prepared by:

ECT
Environmental Consulting & Technology, Inc.

3701 Northwest 98th Street
Gainesville, Florida 32606

ECT No. 990100-0100

September 1999

GRU
GAINESVILLE REGIONAL UTILITIES
Strategic Planning Department

VIA AIRBORNE EXPRESS

September 3, 1999

Mr. Al Linero, Administrator
New Source Review
Florida Dept. of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
J.R. Kelly Generating Station Repowering Project
Applications for Air Construction Permit and Title V Operating Permit Revision

Dear Mr. Linero:

Enclosed are eight (8) copies of the above-referenced permit applications and a check (Check No. 81709) in the amount of $ 7,500.00 in payment of the air construction permit application fee. It is my understanding that the Department will be distributing the permit applications to EPA, the FDEP NE District and Gainesville Branch offices, Alachua County Environmental Protection Dept. and the National Park Service.

Please call me at (352) 334-3400 Ext. 1284 or Mr. Tom Davis at (352) 332-6230 Ext. 351 if you have any questions or need additional information.

Sincerely,

Yolanta E. Jonynas
Sr. Electric Utility Environmental Engineer

xc: D. Beck
D. DuBose, wo. enc.
R. Klemans, wo. enc.
M. Kurtz
S. Manasco, wo. enc.
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JRK CC1

jrkcc1permitdep.y30

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

81709

CITY OF GAINESVILLE
GAINESVILLE REGIONAL UTILITIES

0000081709 08/26/99 002878

INVOICE #	INVOICE DATE	PURCHASE ORDER #	INVOICE AMOUNT	DISCOUNT	NET AMOUNT
082599	08/25/99		7,500.00	0.00	7,500.00
Air construction Permit Application Fee - J.R. Kelly Generating Station Repowering Project					
			7,500.00	0.00	7,500.00

DETACH HERE BEFORE DEPOSITING CHECK

THE FACE OF THIS DOCUMENT HAS A MULTICOLORED BACKGROUND ON WHITE PAPER

GRU

CITY OF GAINESVILLE
GAINESVILLE REGIONAL UTILITIES
GAINESVILLE, FLORIDA

63-115
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81709

08/26/99

SUNTRUST SOUTH CENTRAL FLORIDA, N.A.
OKEECHOBEE OFFICE
OKEECHOBEE, FL 34974

PAY ONLY SEVEN FIVE ZERO ZERO 00 CTS

SEVEN THOUSAND FIVE HUNDRED DOLLARS AND 00 CENTS ***********

******$7,500.00

PAY TO THE ORDER OF

Dept of Env. Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2405

CONTROLLED DISBURSEMENT ACCOUNT

Michael L. Kurtz

VOID OVER $7,500.00 VOID AFTER 180 DAYS

FORM NO. 9704L

[redacted]

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BUREAU OF AIR REGULATION

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

The City of Gainesville, Gainesville Regional Utilities (GRU), is planning to repower its existing J.R. Generating Station located in downtown Gainesville, Alachua County, Florida.

The GRU J.R. Kelly Generating Station presently consists of two operational steam boilers and turbines (Unit Nos. 7 and 8); three simple-cycle combustion turbines (CTs) (CT Unit Nos. 1, 2, and 3); a recirculating cooling water system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. Unit Nos. 7 and 8 have a nominal nameplate electrical generation capacity of 25 and 50 megawatts (MW), respectively, and are fired primarily with natural gas with No. 6 fuel oil serving as a back-up fuel source. Combustion turbine Units Nos. 1, 2, and 3 each have a nominal nameplate electrical generation capacity of 16 MW and are fired with natural gas and distillate fuel oil.

GRU is proposing a repowering project at the J.R. Kelly Generating Station, which will entail adding a new, General Electric (GE) 7EA combustion turbine generator (CTG) and heat recovery steam generator (HRSG) that will operate in conjunction with the existing Unit No. 8 steam turbine. The new CTG (Unit CC-1) will be capable of both simple- and combined-cycle modes of operation and will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. Unit CC-1 will operate at annual capacity factors up to 100 and 11.4 percent for natural gas and oil firing, respectively.

GRU anticipates the new CTG will operate primarily as a combined-cycle unit. In combined-cycle operating mode, Unit CC-1 will utilize an unfired HRSG to produce steam by recovering waste heat from the hot CTG exhaust gases. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine to generate additional electricity. Following installation and commencement of commercial operation of Unit CC-1, the existing Unit No. 8 steam boiler will permanently cease operations. To allow for simple-cycle operations, Unit CC-1 will also include a HRSG bypass stack.

Operation of the proposed repowering project will result in airborne emissions. Therefore, a permit is required prior to the beginning of facility construction, per Rule 62-212.300(1)(a), Florida Administrative Code (F.A.C.). This report, including the required permit application forms and supporting documentation included in the attachments, constitutes GRU'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.

The J.R. Kelly Generating Station Repowering Project will be located in an attainment area and will have potential emissions of a regulated pollutant in excess of 100 tons per year (tpy). The repowering project qualifies as a major modification to an existing major source and is subject to the prevention of significant deterioration (PSD) new source review (NSR) requirements of Section 62-212.400, F.A.C. Therefore, this report and application are also submitted to satisfy the permitting requirements contained in FDEP PSD rules and regulations.

This report is organized as follows:

- Section 1.2 provides an overview and summary of the key regulatory determinations.
- Section 2.0 describes the proposed facility and associated air emissions.
- Section 3.0 describes national and state air quality standards and discusses applicability of NSR procedures to the proposed project.
- Section 4.0 describes the PSD NSR review procedures.
- Section 5.0 provides an analysis of best available control technology (BACT).
- Sections 6.0 (Dispersion Modeling Methodology) and 7.0 (Dispersion Modeling Results) address ambient air quality impacts.

- Section 8.0 discusses current ambient air quality in the vicinity of the J.R. Kelly Generating Station and preconstruction ambient air quality monitoring.
- Section 9.0 addresses other potential air quality impact analyses.
- Section 10.0 lists the references used in preparing the report.

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

1.2 SUMMARY

The J.R. Kelly Generating Station Repowering Project will consist of one GE PG7121 (7EA) CTG used in conjunction with the existing Unit No. 8 steam turbine. New Unit CC-1 will be fired with pipeline-quality natural gas. Low sulfur (containing no more than 0.05 weight percent sulfur [wt%S]) distillate fuel oil will serve as a back-up fuel source.

The planned construction start date for the repowering project is February 2000. The projected date for Unit CC-1 to begin commercial operation is February 2001, following initial equipment start-up and completion of required performance testing.

Based on an evaluation of anticipated worst-case annual operating scenarios, Unit CC-1 will have the potential to emit 207 tpy of nitrogen oxides (NO_x), 189 tpy of carbon monoxide (CO), 24 tpy of particulate matter/particulate matter less than or equal to 10 micrometers aerodynamic diameter (PM/PM_{10}), 47 tpy of sulfur dioxide (SO_2), and 9 tpy of volatile organic compounds (VOCs). Regarding noncriteria pollutants, Unit CC-1 will potentially emit 5 tpy of sulfuric acid (H_2SO_4) mist and trace amounts of heavy metals and organic compounds associated with distillate fuel oil combustion. Because existing Unit 8 will cease operation following installation of Unit CC-1, the *net* emission increases associated with the repowering project will be significantly lower than the Unit CC-1 emission rates. Specifically, the repowering project will result in a net emission increase of 113 tpy of NO_x, 171 tpy of CO, 23 tpy of PM/PM_{10}, 18 tpy of SO_2, and 7 tpy of

VOCs. Based on these annual emission rate potentials, NO_x, CO, and PM_{10} emissions are subject to PSD review.

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

- The use of good combustion practices and clean fuels is considered to be BACT for PM/PM_{10}. Unit CC-1 will utilize the latest advanced burner technologies to maximize combustion efficiency and minimize PM/PM_{10} emission rates and will be fired with pipeline-quality natural gas and low-sulfur, low-ash distillate fuel oil.
- Advanced burner design and good operating practices to minimize incomplete combustion are proposed as CO BACT for Unit CC-1. At baseload operation during natural gas and distillate fuel oil firing, Unit CC-1 CO exhaust concentrations are to be limited to 25 and 20 parts per million by dry volume dry (ppmvd), respectively, for the first year of operation. Thereafter, at baseload operation for both natural gas and distillate fuel oil firing, Unit CC-1 CO exhaust concentrations are to be limited to 20 ppmvd. These concentrations are consistent with prior FDEP BACT determinations for CTGs. Cost effectiveness of a CO oxidation catalyst control system was determined to be $2,029 per ton of CO. Because this cost exceeds values previously determined by FDEP to be cost effective, installation of a CO oxidation catalyst control system is considered to be economically unreasonable.
- Dry low-NO_x (DLN) burner technology is proposed as BACT for NO_x for the repowering project CTG during natural gas firing. For all normal operating loads (60 to 100 percent), Unit CC-1 NO_x exhaust concentration will not exceed 9.0 ppmvd, corrected to 15 percent oxygen (O_2). This concentration is consistent with prior FDEP BACT determinations for natural gas-fired CTGs. Cost effectiveness of a selective catalytic reduction (SCR) control system was determined to be $5,027 per ton of NO_x. Because this cost exceeds values previously determined by FDEP to be cost effective, installation of an SCR control system is considered to be economically unreasonable. During distillate fuel oil firing, water injection will be employed to re-

duce Unit CC-1 NO_x exhaust concentration to 42 ppmvd, corrected to 15-percent oxygen. This is consistent with prior FDEP BACT determinations for oil-fired units.

- The repowering project is projected to emit NO_x, CO, and PM_{10} in greater than PSD significant amounts as specified in Rule 62-212.400, F.A.C. The ambient impact analysis demonstrates that Unit CC-1 impacts will be below the PSD *de minimis* monitoring significance levels for these pollutants. Accordingly, the repowering project 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 air quality impact analysis also demonstrates that CC-1 impacts for the pollutants emitted in significant amounts will be below the PSD significant impact levels defined in Rule 62-210.200(260), F.A.C. Accordingly, a multisource interactive assessment of national ambient air quality standards (NAAQS) attainment and PSD Class I and II increment consumption was not required.
- Based on refined dispersion modeling, the repowering project 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.
- The additional impact analysis also demonstrates that repowering project impacts will be well below levels that are detrimental to soils and vegetation and will not impair visibility.
- The nearest PSD Class I area (Okefenokee National Wildlife Refuge [NWR]) is located approximately 102 kilometers (km) north of the J.R. Kelly Generating Station site. The Chassahowitzka NWR is located approximately 103 km southwest of the project site. Air quality and visibility impacts on these Class I areas will be negligible.

2.0 DESCRIPTION OF THE PROPOSED FACILITY

2.1 REPOWERING PROJECT DESCRIPTION, AREA MAP, AND PLOT PLAN

The proposed new CTG will be located at GRU's existing J.R. Kelly Generating Station. The J.R. Kelly Generating Station is situated at 605 Southeast 3rd Street in downtown Gainesville, Alachua County, Florida. Figure 2-1 provides portions of a U.S. Geological Survey (USGS) topographical map showing the location of the J.R. Kelly Generating Station and nearby prominent geographical features.

The proposed J.R. Kelly Generating Station Repowering Project consists of the addition of one, GE PG7121 (7EA) CTG and an HRSG together with continued use of the existing Unit No. 8 steam turbine. New Unit CC-1 will be capable of both simple- and combined-cycle modes of operation and will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a supplemental, back-up fuel source.

In combined-cycle operating mode, Unit CC-1 will utilize an unfired HRSG to produce steam by recovering waste heat from the hot CTG exhaust gases. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine to generate additional electricity. Unit CC-1 will have a nominal electrical generation capacity of 133 MW at baseload (100-percent load), 59 degrees Fahrenheit (°F) ambient air temperature, 60-percent relative humidity, and natural gas-firing during combined-cycle operating mode conditions. During distillate fuel oil firing, Unit CC-1 will have a nominal electrical generation capacity of 136 MW.

To allow for simple-cycle operations and minimize emissions during start-up for combined-cycle operations, Unit CC-1 will also include a HRSG bypass stack. In simple-cycle operating mode, Unit CC-1 will have a nominal electrical generation capacity of 83 MW at baseload, 59°F ambient air temperature, 60-percent relative humidity, and natural gas-firing. During distillate fuel oil firing, Unit CC-1 will have a nominal electrical generation capacity of 86 MW in simple-cycle operating mode.

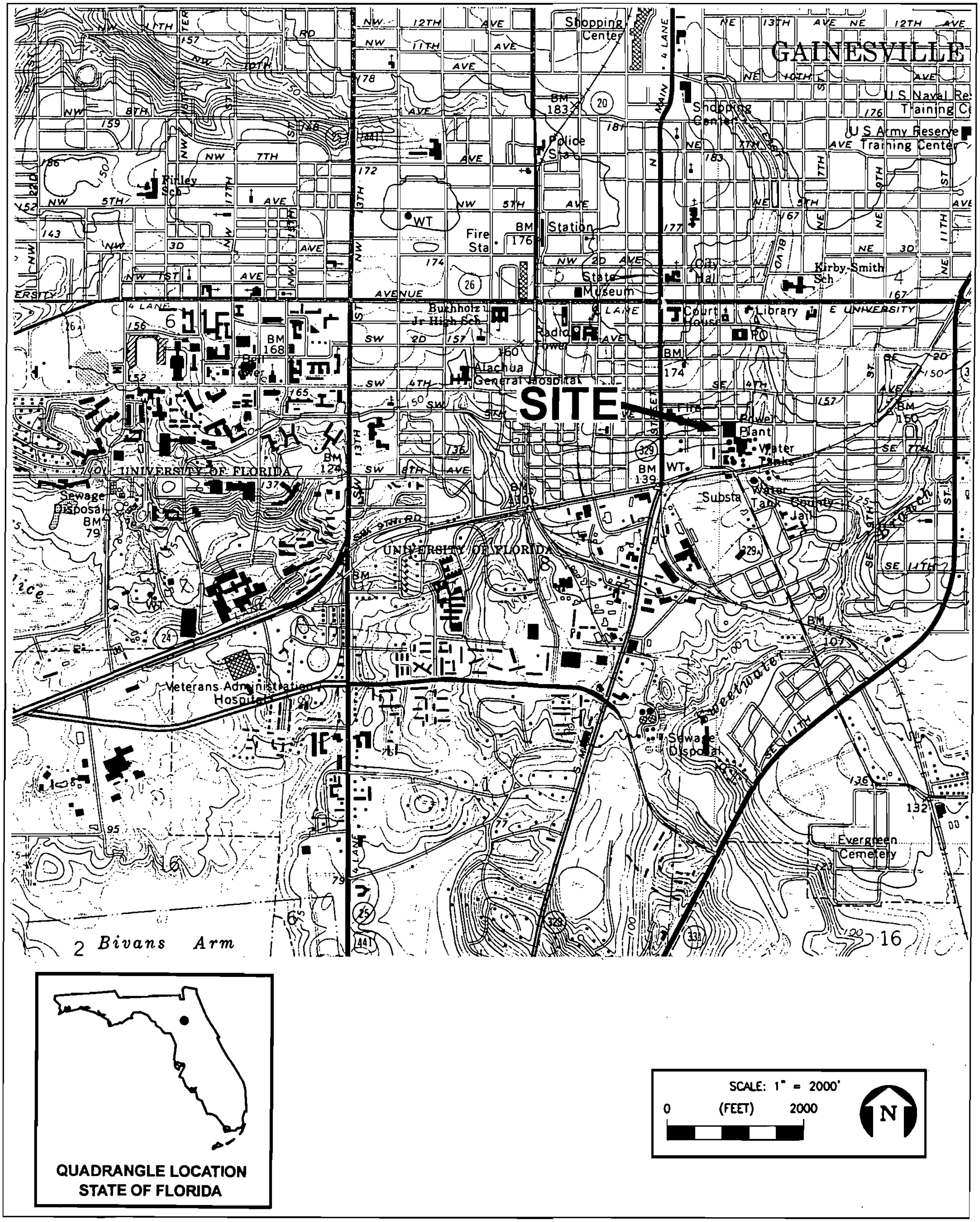


FIGURE 2-1.
J.R. KELLY GENERATING STATION LOCATION MAP

Source: USGS Quad: Gainesville East, FL, 1988.

GRU

Unit CC-1 will operate at annual capacity factors up to 100 and 11.4 percent for natural gas and oil firing fuel consumption, respectively. At baseload operation, these annual capacity factors are equivalent to 8,760 and 1,000 hours per year (hr/yr) for natural gas and oil firing, respectively. Unit CC-1 will normally operate between 60- and 100-percent load.

Combustion of natural gas and distillate fuel oil in Unit CC-1 will result in emissions of PM/PM_{10}, SO_2, NO_x, CO, VOCs, and H_2SO_4 mist. Emission control systems proposed for Unit CC-1 include the use of DLN combustors (natural gas firing) and water injection (distillate fuel oil firing) for control of NO_x; good combustion practices for abatement of CO and VOCs; and use of clean, low-sulfur, low-ash natural gas and distillate fuel oil to minimize PM/PM_{10}, SO_2, and H_2SO_4 mist emissions.

A plot plan showing the existing J.R. Kelly Generating Station emission sources, major process equipment and structures, and the new Unit CC-1 emission points is provided in Figure 2-2. Primary access to the J.R. Kelly Generating Station is from Southeast 5th Avenue on the north side of the plant site. The J.R. Kelly Generating Station entrance has fencing and a security system to control site access.

2.2 PROCESS DESCRIPTION AND PROCESS FLOW DIAGRAM

The proposed repowering project will include one nominal 83-MW CTG referred to as Unit CC-1. Figure 2-3 presents a process flow diagram of new Unit CC-1.

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 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. The compressed combustion air is then combined with filtered natural gas fuel or distillate fuel oil and burned in the CTG's high-pressure combustors to produce hot exhaust gases. These high-pressure, hot gases next expand and turn the CTG's turbine to produce rotary shaft power, which is used to drive an electric

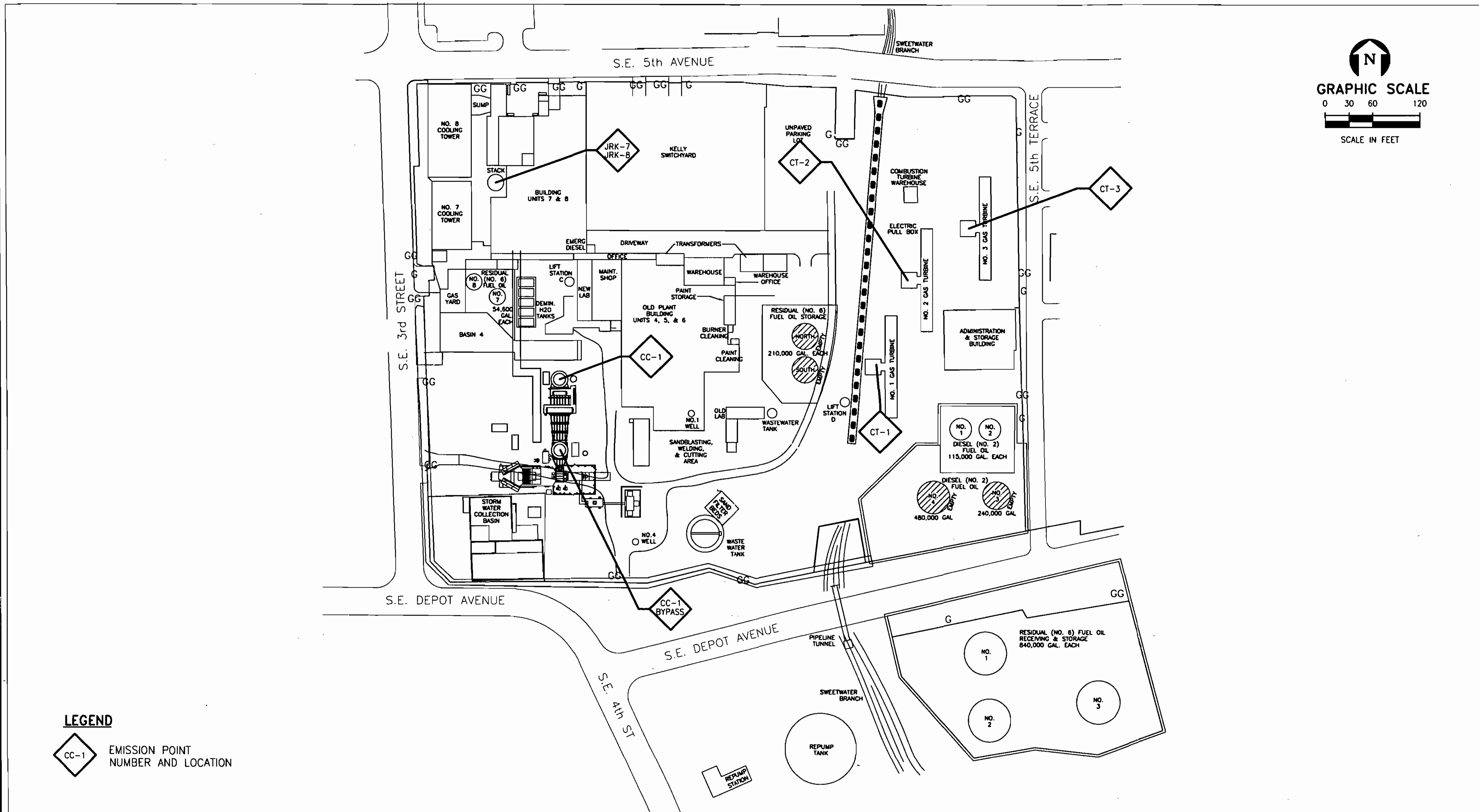
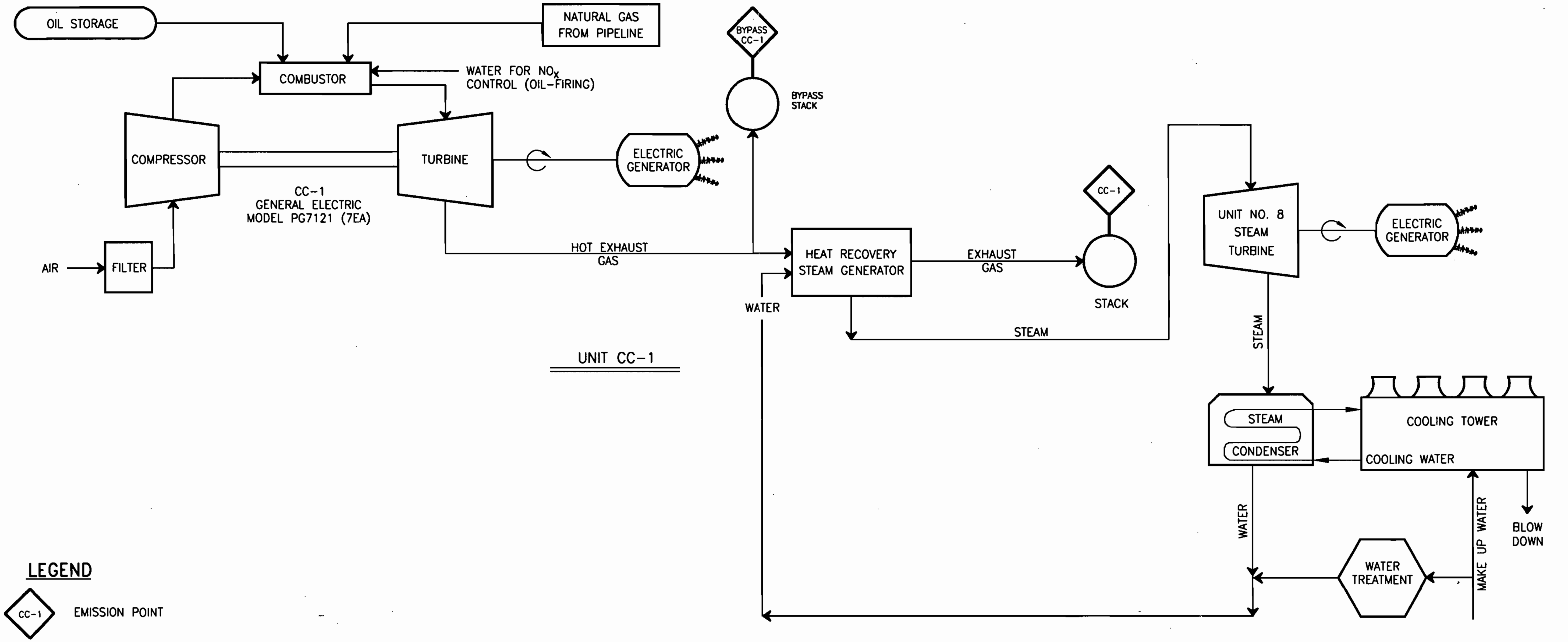


FIGURE 2-2.

J.R. KELLY GENERATING STATION PLOT PLAN

Source: GRU, 1999.

GRU



FIGURE

UNIT CC-1: PROCESS FLOW DIAGRAM

Source: ECT, 1999.

GRU

generator as well as the CTG combustion air compressor. In simple-cycle mode, the hot exhaust gases are then vented to the atmosphere through a by-pass stack.

As mentioned previously, the CTG will be equipped with a HRSG. During combined-cycle mode of operation, the hot exhaust gases from the CTG will flow to the HRSG for the production of low- and high-pressure steam. Steam produced by the HRSG will used to power the existing Unit 8 steam turbine (ST). The ST, in turn, will drive an existing electric generator having a nominal generation capacity of 50 MW. The HRSG will be unfired (i.e., the unit will not include the capability of supplement duct burner firing). Following reuse of the CTG exhaust waste heat by the HRSG, the exhaust gases are vented to the atmosphere. During startups, the exhaust ducting configuration will allow a portion of the CTG exhaust gases to flow to the HRSG with the remainder exhausted through the simple-cycle HRSG by-pass stack.

Normal operation is expected to consist of the Unit CC-1 operating at baseload in combined-cycle mode fired with natural gas. Alternate operating modes include distillate fuel oil firing and simple-cycle and reduced load (i.e., between 60 and 100 percent of baseload) operations depending on fuel availability and power demands. As noted previously, Unit CC-1 may operate at annual capacity factors up to 100 and 11.4 percent for natural gas and oil firing, respectively. Permit conditions authorizing continuous operation with natural gas-firing (i.e., 8,760 hours per year) and up to 8,001,200 gallons per year of distillate fuel oil usage are requested.

Rule 62-210.700(1), F.A.C., allows for excess emissions due to start-up, shut-down, or malfunction for no more than 2 hours in any 24-hour period unless specifically authorized by FDEP for a longer duration. Because Unit CC-1 warm and cold start periods will last for 180 and 240 minutes, respectively, excess emissions for up to 4 hours in any 24-hour period are requested. Unit CC-1 start-up is defined as that period of time from initiation of CTG firing until Unit CC-1 reaches steady-state load operation. Steady-state operation is reached when Unit CC-1 reaches minimum load (e.g., 60-percent load). A warm start is defined as a start-up that occurs when the Unit CC-1 has not operated for more than 2 hours and less than or equal to 48 hours. A cold start is defined as a start-up that occurs when the CC-1 has not operated for more than 48 hours.

Unit CC-1 will utilize DLN combustion technology (natural-gas firing) and water injection (distillate fuel-oil firing) to control NO_x air emissions. The use of low-sulfur natural gas and distillate fuel oil in the CTG will minimize PM/PM_{10}, SO_2, and H_2SO_4 mist air emissions. High efficiency combustion practices will be employed to control CO and VOC emissions.

2.3 EMISSION AND STACK PARAMETERS

Tables 2-1 and 2-2 provide maximum hourly criteria pollutant Unit CC-1 emission rates for natural gas and distillate fuel oil firing, respectively. Maximum hourly H_2SO_4 mist emission rates for natural gas and distillate fuel oil firing are summarized in Table 2-3. Maximum hourly noncriteria pollutant rates for natural gas and distillate fuel oil firing are provided in Tables 2-4 and 2-5, respectively. The highest hourly emission rates for each pollutant are shown, taking into account load and ambient temperature to develop maximum hourly emission estimates for the CTG. Noncriteria pollutants consist primarily of trace amounts of organic and inorganic compounds associated with the combustion of distillate fuel oil.

In general, maximum hourly emission rates for all pollutants, in units of pounds per hour (lb/hr), are projected to occur for CTG operations at low ambient temperature (i.e., 20°F), baseload, and fuel oil firing. Maximum hourly CO and VOC emission rates, during natural gas-firing, are projected to occur at an ambient temperature of 95°F and 60 percent load. The bases for these emission rates are provided in Attachment D.

Table 2-6 presents projected maximum annualized criteria and noncriteria emissions for Unit CC-1. The maximum annualized rates were conservatively estimated assuming baseload operation for 7,760 hr/yr (natural gas firing), baseload operation for 1,000 hr/yr (fuel oil firing), and an ambient temperature of 59°F. As noted previously, existing Unit 8

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

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100†	20	5.0	0.63	6.0	0.76	36.0	4.54	59.0	7.43	2.0	0.25	Neg.	Neg.
	59	5.0	0.63	5.5	0.69	32.0	4.03	54.0	6.80	1.8	0.23	Neg.	Neg.
	95	5.0	0.63	4.3	0.62	29.0	3.65	49.0	6.17	1.8	0.23	Neg.	Neg.
100	20	5.0	0.63	6.0	0.76	36.0	4.54	47.2	5.95	2.0	0.25	Neg.	Neg.
	59	5.0	0.63	5.5	0.69	32.0	4.03	43.2	5.44	1.8	0.23	Neg.	Neg.
	95	5.0	0.63	4.3	0.62	29.0	3.65	39.2	4.94	1.8	0.23	Neg.	Neg.
80	20	5.0	0.63	5.0	0.63	29.0	3.65	57.0	7.18	3.6	0.45	Neg.	Neg.
	59	5.0	0.63	4.6	0.58	27.0	3.40	44.0	5.54	1.8	0.23	Neg.	Neg.
	95	5.0	0.63	3.9	0.53	25.0	3.15	40.0	5.04	1.4	0.18	Neg.	Neg.
60	20	5.0	0.63	4.3	0.54	25.0	3.15	47.0	5.92	2.8	0.35	Neg.	Neg.
	59	5.0	0.63	4.2	0.50	23.0	2.90	40.0	4.66	1.4	0.18	Neg.	Neg.
	95	5.0	0.63	3.6	0.45	21.0	2.65	63.0	7.94	4.0	0.50	Neg.	Neg.

Note: Neg. = negligible

*As measured by EPA Reference Method 5B or 17.
†First year operations.

Sources: GE, 1999
ECT, 1999.

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

Unit Load (%)	Ambient Temperature (°F)	PM/PM_{10}*		SO_2		NO_x		CO		VOC		Lead	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	10.0	1.26	57.6	7.26	185.0	23.31	47.0	5.92	5.0	0.63	0.065	0.0082
	59	10.0	1.26	51.9	6.53	166.0	20.92	43.0	5.42	4.5	0.57	0.058	0.0074
	95	10.0	1.26	46.2	5.82	148.0	18.65	39.0	4.91	4.5	0.57	0.052	0.0066
80	20	10.0	1.26	48.4	6.10	154.0	19.40	37.0	4.66	4.0	0.50	0.055	0.0069
	59	10.0	1.26	43.9	5.53	140.0	17.64	35.0	4.41	4.0	0.50	0.050	0.0062
	95	10.0	1.26	39.5	4.98	126.0	15.88	32.0	4.03	3.5	0.44	0.045	0.0056
60	20	10.0	1.26	40.9	5.15	129.0	16.25	32.0	4.03	3.5	0.44	0.046	0.0058
	59	10.0	1.26	37.3	4.69	118.0	14.87	30.0	3.78	3.0	0.38	0.042	0.0053
	95	10.0	1.26	33.6	4.23	106.0	13.36	28.0	3.53	3.0	0.38	0.038	0.0048

*As measured by EPA Reference Method 5B or 17.

Sources: GE, 1999.
ECT, 1999.

Table 2-3. Maximum H_2SO_4 Mist Pollutant Emission Rates for Three Loads and Three Ambient Temperatures

Unit Load (%)	Ambient Temperature (°F)	Natural Gas H_2SO_4 mist		Distillate Fuel Oil H_2SO_4 mist	
		lb/hr	g/s	lb/hr	g/s
100	20	0.69	0.087	6.62	0.083
	59	0.63	0.079	5.95	0.750
	95	0.55	0.071	5.32	0.670
80	20	0.58	0.073	5.56	0.700
	59	0.53	0.067	5.04	0.636
	95	0.48	0.061	4.54	0.572
60	20	0.49	0.062	4.69	0.591
	59	0.45	0.057	4.28	0.539
	95	0.41	0.052	3.86	0.486

Sources: GE, 1999.
ECT, 1999.

Table 2-4. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load ("Baseload") and Three Temperatures—Natural Gas

Unit Load (%)	Ambient Temp. (°F)	Arsenic		Benzene		Cadmium		Chromium VI		Cobalt		Dioxins/Furans	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	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
	95	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)	Formaldehyde		Manganese		Mercury		Napthalene		Nickel		Phosphorus	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	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
	95	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

Unit Load (%)	Ambient Temp. (°F)	Polycyclic Organic Matter		Toluene	
		lb/hr	g/s	lb/hr	g/s
100	20	5.41E-05	6.82E-06	1.10E-02	1.39E-03
	59	4.89E-05	6.16E-06	9.97E-03	1.26E-03
	95	4.41E-05	5.55E-06	8.99E-03	1.13E-03

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

Source: ECT, 1999.

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load ("Baseload") and Three Temperatures (Per CTG)—Distillate Fuel Oil

Unit Load (%)	Ambient Temp. (°F)	Acetaldehyde		Antimony		Arsenic		Benzene		Beryllium		Cadmium	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	9.19E-03	1.16E-03	2.47E-02	3.11E-03	5.49E-03	6.92E-04	1.57E-03	1.98E-04	3.70E-04	4.66E-05	4.71E-03	5.93E-04
	59	8.27E-03	1.04E-03	2.22E-02	2.80E-03	4.94E-03	6.23E-04	1.41E-03	1.78E-04	3.33E-04	4.19E-05	4.24E-03	5.34E-04
	95	7.37E-03	9.29E-04	1.98E-02	2.49E-03	4.41E-03	5.55E-04	1.26E-03	1.59E-04	2.97E-04	3.74E-05	3.78E-03	4.76E-04

Unit Load (%)	Ambient Temp. (°F)	Chromium		Cobalt		Dioxins/Furans		Ethylbenzene		Formaldehyde		Hydrogen Chloride	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	5.27E-02	6.64E-03	1.02E-02	1.28E-03	9.85E-07	1.24E-07	5.49E-04	6.92E-05	3.36E-02	4.24E-03	2.58E+00	3.25E-01
	59	4.74E-02	5.97E-03	9.18E-03	1.16E-03	8.86E-07	1.12E-07	4.94E-04	6.23E-05	3.03E-02	3.81E-03	2.32E+00	2.92E-01
	95	4.23E-02	5.32E-03	8.18E-03	1.03E-03	7.90E-07	9.96E-08	4.41E-04	5.55E-05	2.70E-02	3.40E-03	2.07E+00	2.61E-01

Unit Load (%)	Ambient Temp. (°F)	Hydrogen Fluoride		Manganese		Methyl Chloroform		Methylene Chloride		Mercury		Naphthalene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.57E-01	1.98E-02	3.81E-01	4.80E-02	8.52E-03	1.07E-03	3.61E-02	4.55E-03	1.02E-03	1.28E-04	3.81E-04	4.80E-05
	59	1.41E-01	1.78E-02	3.43E-01	4.32E-02	7.66E-03	9.66E-04	3.25E-02	4.10E-03	9.18E-04	1.16E-04	3.43E-04	4.32E-05
	95	1.26E-01	1.59E-02	3.06E-01	3.85E-02	6.83E-03	8.61E-04	2.90E-02	3.65E-03	8.18E-04	1.03E-04	3.06E-04	3.85E-05

Table 2-5. Maximum Noncriteria Pollutant Emission Rates for 100 Percent Load ("Baseload") and Three Temperatures (Per CTG)—Distillate Fuel Oil (Continued, Page 2 of 2)

Unit Load (%)	Ambient Temp. (°F)	Nickel		Phenol		Phosphorus		Polycyclic Organic Matter		Selenium		Tetrachloroethylene	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	1.34E+00	1.69E-01	2.72E-02	3.43E-03	3.36E-01	4.24E-02	7.55E-04	9.52E-05	5.94E-03	7.48E-04	6.16E-04	7.77E-05
	59	1.21E+00	1.52E-01	2.45E-02	3.09E-03	3.03E-01	3.81E-02	6.80E-04	8.56E-05	5.35E-03	6.73E-04	5.55E-04	6.99E-05
	95	1.08E+00	1.36E-01	2.18E-02	2.75E-03	2.70E-01	3.40E-02	6.06E-04	7.64E-05	4.77E-03	6.00E-04	4.95E-04	6.23E-05

Unit Load (%)	Ambient Temp. (°F)	Toluene		Vinyl Acetate		Xylenes	
		lb/hr	g/s	lb/hr	g/s	lb/hr	g/s
100	20	8.96E-03	1.13E-03	5.77E-03	7.27E-04	2.45E-03	3.09E-04
	59	8.07E-03	1.02E-03	5.19E-03	6.54E-04	2.21E-03	2.78E-04
	95	7.19E-03	9.06E-04	4.63E-03	5.83E-04	1.97E-03	2.48E-04

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

Source: ECT, 1999.

Table 2-6. Maximum Annualized Emission Rates (tpy)

Pollutant	Unit CC-1* (tpy)
NO_x	207
CO†	231
CO	189
PM/PM_{10}**	24
SO_2	47
VOC	9
H_2SO_4 mist	5
Acetaldehyde	4.13E-03
Antimony	1.11E-02
Arsenic	3.07E-03
Benzene	6.70E-03
Beryllium	1.66E-04
Cadmium	2.31E-03
Chromium	2.78E-02
Cobalt	5.10E-03
Dioxins/Furans	4.48E-07
Ethylbenzene	2.47E-04
Formaldehyde	1.39E-01
Hydrogen Chloride	1.16E+00
Hydrogen Fluoride	7.06E-02
Lead	3.08E-02
Manganese	1.73E-01
Methyl Chloroform	3.83E-03
Methylene Chloride	1.63E-02
Mercury	4.62E-04
Naphthalene	3.04E-03
Nickel	6.15E-01
Phenol	1.23E-02
Phosphorus	1.61E-01
Polycyclic Organic Matter	5.54E-04
Selenium	2.67E-03
Tetrachloroethylene	2.77E-04
Toluene	4.77E-02
Vinyl Acetate	2.60E-03
Xylenes	1.10E-03

*Based on baseload operations for 7,760 hr/yr on natural gas and 1,000 hr/yr on fuel oil.
†First year operation.
**As measured by EPA Reference Method 5B or 17.

Sources: GRU, 1999.
GE, 1999.
ECT, 1999.

boiler will cease operation following installation of Unit CC-1. The net annual emission increases associated with the repowering project are shown in Table 2-7.

Stack parameters for simple-cycle mode operations are provided in Tables 2-8 and 2-9 for natural gas and distillate fuel oil firing, respectively. Stack parameters for combined-cycle mode operations are provided in Tables 2-10 and 2-11 for natural gas and distillate fuel oil firing, respectively.

Table 2-7. Repowering Project – Net Annual Emission Rate Increases (tpy)

Pollutant	Repowering Project* (tpy)
NO_x	113
CO†	213
CO	171
PM/PM_{10}**	23
SO_2	18
VOC	7
H_2SO_4 mist	4

*Based on CC-1 baseload operations for 7,760 hr/yr on natural gas and 1,000 hr/yr on fuel oil.
†First year operation.
**As measured by EPA Reference Method 5B or 17.

Sources: GRU, 1999.
GE, 1999.
ECT, 1999.

Table 2-8. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas, Simple-Cycle Mode

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	78	23.8	974	796	139.1	42.4	15.5	4.71
	59	78	23.8	1,001	811	130.2	39.7	15.5	4.71
	95	78	23.8	1,025	825	121.7	37.1	15.5	4.71
80	20	78	23.8	1,004	813	115.5	35.2	15.5	4.71
	59	78	23.8	1,037	831	109.7	33.4	15.5	4.71
	95	78	23.8	1,078	854	104.0	31.7	15.5	4.71
60	20	78	23.8	1,055	841	100.7	30.7	15.5	4.71
	59	78	23.8	1,091	861	96.1	29.3	15.5	4.71
	95	78	23.8	1,100	866	91.8	28.0	15.5	4.71

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

Sources: GE, 1999.
ECT, 1999.

Table 2-9. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Oil, Simple-Cycle Mode

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	78	23.8	968	793	141.2	43.1	15.5	4.71
	59	78	23.8	996	809	132.0	40.2	15.5	4.71
	95	78	23.8	1,021	823	122.9	37.5	15.5	4.71
80	20	78	23.8	1,041	834	116.8	35.6	15.5	4.71
	59	78	23.8	1,058	843	110.9	33.8	15.5	4.71
	95	78	23.8	1,076	853	104.8	32.0	15.5	4.71
60	20	78	23.8	1,086	859	101.8	31.0	15.5	4.71
	59	78	23.8	1,099	866	97.0	29.6	15.5	4.71
	95	78	23.8	1,100	866	92.5	28.2	15.5	4.71

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

Sources: GE, 1999.
ECT, 1999.

Table 2-10. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Natural Gas, Combined-Cycle Mode

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	100	30.5	248	393	68.6	20.9	15.5	4.71
	59	100	30.5	242	390	62.5	19.1	15.5	4.71
	95	100	30.5	239	388	57.3	17.5	15.5	4.71
80	20	100	30.5	235	386	54.8	16.7	15.5	4.71
	59	100	30.5	232	384	50.7	15.5	15.5	4.71
	95	100	30.5	230	383	46.6	14.2	15.5	4.71
60	20	100	30.5	226	381	45.6	13.9	15.5	4.71
	59	100	30.5	224	380	42.4	12.9	15.5	4.71
	95	100	30.5	225	380	40.3	12.3	15.5	4.71

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

Sources: GE, 1999.
ECT, 1999.

Table 2-11. Stack Parameters for Three Unit Loads and Three Ambient Temperatures—Distillate Oil, Combined-Cycle Mode

Unit Load (%)	Ambient Temperature (°F)	Stack Height		Stack Exit Temperature		Stack Exit Velocity		Stack Diameter	
		ft	meters	°F	K	ft/sec	m/sec	ft	meters
100	20	100	30.5	302	423	75.4	23.0	15.5	4.71
	59	100	30.5	296	420	68.6	20.9	15.5	4.71
	95	100	30.5	291	417	62.4	19.0	15.5	4.71
80	20	100	30.5	292	418	58.6	17.8	15.5	4.71
	59	100	30.5	286	414	54.5	16.6	15.5	4.71
	95	100	30.5	283	413	50.7	15.5	15.5	4.71
60	20	100	30.5	289	416	49.3	15.0	15.5	4.71
	59	100	30.5	280	411	46.1	14.0	15.5	4.71
	95	100	30.5	279	411	43.8	13.4	15.5	4.71

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

Sources: GE, 1999.
ECT, 1999.

3.0 AIR QUALITY STANDARDS AND NEW SOURCE REVIEW APPLICABILITY

3.1 NATIONAL AND STATE AAQS

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

Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements. The J.R. Kelly Generating Station is located in downtown Gainesville in Alachua County. Alachua County is presently designated in 40 CFR 81.310 as better than national standards (for total suspended particulates [TSPs] and SO_2), unclassifiable/attainment (for CO), unclassifiable or better than national standards (for nitrogen dioxide [NO_2]), and not designated (for lead). 40 CFR 81.310 also indicates the 1-hour ozone standard is not applicable. Alachua 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.

3.2 NONATTAINMENT NSR APPLICABILITY

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

3.3 PSD NSR APPLICABILITY

The existing J.R. Kelly Generating Station is classified as a *major facility.* A modification to a major facility which has potential net emissions equal to or exceeding the significant

Table 3-1. National and Florida Air Quality Standards (micrograms per cubic meter [μg/m³] unless otherwise stated)

Pollutant (units)	Averaging Periods	National Standards Primary	National Standards Secondary	Florida Standards
SO_2 (ppmv)	3-hour[1]		0.5	0.5
	24-hour[1]	0.14		0.1
	Annual[2]	0.030		0.02
SO_2	3-hour[1]			1,300
	24-hour[1]			260
	Annual[2]			60
PM_{10}[13]	24-hour[3]	150	150	
	Annual[4]	50	50	
PM_{10}	24-hour[5]			150
	Annual[6]			50
$PM_{2.5}$[11,12]	24-hour[7]	65	65	
	Annual[8]	15	15	
CO (ppmv)	1-hour[1]	35		35
	8-hour[1]	9		9
CO	1-hour[1]			40,000
	8-hour[1]			10,000
Ozone (ppmv)	1-hour[9]			0.12
	8-hour[10,11]	0.08	0.08	
NO_2 (ppmv)	Annual[2]	0.053	0.053	0.05
NO_2	Annual[2]			100
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	1.5

1 Not to be exceeded more than once per calendar year.
2 Arithmetic mean.
3 Standard attained when the 99th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
4 Arithmetic mean, as determined by 40 CFR 50, Appendix N.
5 Not to be exceeded more than once per year, as determined by 40 CFR 50, Appendix K.
6 Standard attained when the expected annual arithmetic mean is less than or equal to the standard, as determined by 40 CFR 50, Appendix K.
7 Standard attained when the 98th percentile is less than or equal to the standard, as determined by 40 CFR 50, Appendix N.
8 Arithmetic mean, as determined by 40 CFR 50, Appendix N.
9 Standard attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than 1, as determined by 40 CFR 50, Appendix H.
10 Standard attained when the average of the annual 4th highest daily maximum 8-hour average concentration is less than or equal to the standard, as determined by 40 CFR 50, Appendix I.
11 The U.S. Court of Appeals for the District of Columbia Circuit (Circuit Court) held that these standards are not enforceable. American Trucking Association v. U.S.E.P.A., 1999 WL300618 (Circuit Court).
12 In a July 30, 1999 decision, the Circuit Court decided not to vacate these standards. Standards were remanded to EPA.
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.

emission rates indicated in Section 62-212.400, Table 212.400-2, F.A.C., is subject to PSD NSR.

Net emission rates from the repowering project will exceed the significant emission rate thresholds. Therefore, the repowering project qualifies as a major modification to a 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 repowering project and the PSD significant emission rate thresholds are provided in Table 3-2. As shown in this table, potential emissions of NO_x, CO, and PM_{10} are each projected to exceed the applicable PSD significant emission rate level. These pollutants are, therefore, subject to the PSD NSR requirements of Section 62-212.400, F.A.C. Attachment D provides detailed emission rate estimates for the repowering project.

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

Pollutant	Repowering Project Net Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	PSD Applicability
NO_x	113	40	Yes
CO*	213	100	Yes
CO	171	100	Yes
PM	23	25	No
PM_{10}	23	15	Yes
SO_2	18	40	No
Ozone/VOC	7	40	No
Lead	Negligible	0.6	No
Mercury	Negligible	0.1	No
Total fluorides	Negligible	3	No
H_2SO_4 mist	5	7	No
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 applicable	40	No
Municipal waste combustor metals (measured as PM)	Not applicable	15	No
Municipal waste combustor organics (measured as total tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans)	Not applicable	3.5×10^{-6}	No

*First year operation.

Sources: Section 62-212.400, Table 212.400-2, F.A.C.
ECT, 1999.

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 repowering project in amounts equal to or greater than the PSD significant emission rate levels. As defined by Rule 62-210.200(42), F.A.C., BACT is:

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

BACT determinations are made on a case-by-case basis as part of the FDEP NSR process and apply to each pollutant which exceeds the PSD significant emission rate thresholds shown in Table 3-2. All emission units involved in a major modification or a new major source that emit or increase emissions of the applicable pollutants must undergo BACT analysis. Because each applicable pollutant must be analyzed, particular emission units may undergo BACT analysis for more than one pollutant.

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

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

4.2 AMBIENT AIR QUALITY MONITORING

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

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

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 Section 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 proposed repowering project 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 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.

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.

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(259), F.A.C.

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

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

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 enforceable (reference *American Trucking Association versus U.S. EPA, 1999 WL300618, [Circuit Court]*). In addition, due to the significant technical difficulties that exist with respect to $PM_{2.5}$ monitoring, emissions estimation, and modeling, EPA has determined that implementation of PSD permitting for $PM_{2.5}$ is administratively impracticable at this time for State permitting authorities. Accordingly, EPA has advised that PM_{10} may be used as a surrogate for $PM_{2.5}$ in meeting NSR requirements until these difficulties are resolved.

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

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

- 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 are not 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.

Table 4-3. PSD Allowable Increments ($\mu g/m^3$)

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.

- Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

It is not necessary to make a determination of the baseline concentration to determine the amount of PSD increment consumed. Instead, increment consumption calculations need only reflect the ambient pollutant concentration *change* attributable to emission sources that affect increment. *Major source baseline date* means January 6, 1975, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2. *Minor source baseline date* means the earliest date after the trigger date, on which the first complete permit application (in Florida, December 27, 1977, for PM/PM_{10} and SO_2 and March 28, 1988, for NO_x) was submitted by a major stationary source or major modification subject to the requirements of 40 CFR 52.21 or Section 62-212.400, F.A.C. The trigger dates are August 7, 1977, for PM (TSP/PM_{10}) and SO_2 and February 8, 1988, for NO_2.

The ambient impact analysis for the repowering project 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 repowering project under review. A more extensive analysis would be conducted for repowering projects having large emission increases than those that will cause a small increase in emissions.

The growth analysis generally includes:

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

- An air quality analysis based on the associated growth emission estimates and the emissions expected to be generated directly by the new source or modification.

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

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

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

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 METHODOLOGY

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

- EPA reasonably available control technology (RACT)/BACT/lowest achievable emission rate (LAER) Clearinghouse (RBLC) via the RBLC Information System database.
- EPA NSR web site.
- EPA Control Technology Center (CTC) web site.
- Recent FDEP BACT determinations for similar facilities.
- Vendor information.
- Environmental Consulting & Technology, Inc. (ECT), experience for similar CT 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 × purchased equipment cost
Sales tax	0.06 × purchased equipment cost
Freight	0.05 × purchased equipment cost
Foundations and supports	0.08 × purchased equipment cost
Handling and erection	0.14 × purchased equipment cost
Electrical	0.04 × purchased equipment cost
Piping	0.02 × purchased equipment cost
Insulation	0.01 × purchased equipment cost
Painting	0.01 × purchased equipment cost
Indirect Capital Costs	
Engineering	0.10 × purchased equipment cost
Construction and field expenses	0.05 × purchased equipment cost
Contractor fees	0.10 × purchased equipment cost
Start-up	0.02 × purchased equipment cost
Performance testing	0.01 × purchased equipment cost
Contingencies	0.03 × purchased equipment cost
Direct Annual Operating Costs	
Supervisor labor	0.15 × total operator labor cost
Maintenance materials	1.00 × total maintenance labor cost
Indirect Annual Operating Costs	
Overhead	0.60 × total of operating, supervisory, and maintenance labor and maintenance materials
Administrative charges	0.02 × total capital investment
Property taxes	0.01 × total capital investment
Insurance	0.01 × 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, net annual emission rate increases of NO_x, CO, and PM_{10} for the repowering project 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_{10}), products of incomplete combustion (CO), and acid gases (NO_x), 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 60), NESHAPs (40 CFR 61 and 63), and FDEP emission standards (Chapter 62-296, F.A.C., *Stationary Sources—Emission Standards*).

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

- Electric utility stationary gas turbines with a heat input at peak load of greater than 100 million British thermal units per hour (MMBtu/hr) based on the lower heating value (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 International Standards Organization (ISO) standard day conditions of 30 MW or less.

The electric utility stationary gas turbine NSPS applicability criterion applies to stationary gas turbines that sell more than one-third of their potential electric output to any utility power distribution system. The repowering project CTG qualifies as an electric utility stationary gas turbine and, therefore, is 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. The proposed

CTG has no applicable NESHAPs/maximum achievable control technology (MACT) requirements.

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-.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.

Emission standards applicable to sources located in nonattainment areas are contained in Sections 62-296.500 (for ozone nonattainment and maintenance areas) and 62-296.700, F.A.C. (for PM nonattainment and maintenance areas). Because the repowering project is located in Alachua County, Florida, and because this county is designated attainment for all criteria pollutants, these emission standards are not applicable. Finally, Section 62-204.800, F.A.C., adopts federal NSPS and NESHAPs, respectively, by reference. As noted previously, NSPS Subpart GG, *Stationary Gas Turbines* is applicable to the repowering project. There are no applicable NESHAPs requirements.

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

5.3 BACT ANALYSIS FOR PM_{10}

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

Table 5-2. Federal Emission Limitations

NSPS Subpart GG, Stationary Gas Turbines

Pollutant	Emission Limitation
NO_x	$STD = 0.0075 \times (14.4/Y) + F$

where: STD = allowable NOx emissions (percent by volume at 15-percent oxygen 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 (FNB) per:

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

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

SO_2 = $\leq$0.015 percent by volume at 15-percent oxygen 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_{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_{10} is filtered from the gas stream by various mechanisms (inertial impaction, impingement, accumulated dust cake sieving, etc.) as the gas passes through the fabric filter. Accumulated dust on the bags is periodically removed using mechanical or pneumatic means. In pulse jet pneumatic cleaning, a sudden pulse of compressed air is injected into the top of the bag. This pulse creates a traveling wave in the fabric that separates the cake from the surface of the fabric. The cleaning normally proceeds by row, all bags in the row being cleaned simultaneously. Typical air-to-cloth ratios range from 2 to 8 cubic feet per minute-square foot ($cfm\text{-}ft^2$).

Collection efficiencies are on the order of 99 percent for particles smaller than 2.5 microns in size.

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

While all of these postprocess technologies would be technically feasible for controlling PM_{10} emissions from CTGs, none of the previously described control equipment have been applied to CTGs because exhaust gas PM_{10} concentrations are inherently low. CTGs operate with a significant amount of excess air, which generates large exhaust gas flow rates. The repowering project CTG will be fired with natural gas as the primary fuel and distillate fuel oil as the back-up fuel source. Combustion of natural gas and distillate fuel oil will generate low PM_{10} emissions in comparison to other fuels due to their low ash and sulfur contents. The minor PM_{10} emissions coupled with a large volume of exhaust gas produces extremely low exhaust stream PM_{10} concentrations. The estimated PM_{10} exhaust concentration for the repowering project CTG during oil-firing at base load and 59°F is approximately 0.002 grains per dry standard cubic foot (gr/dscf). Exhaust stream PM_{10} concentrations of such low magnitude are not amenable to control using available technologies because removal efficiencies would be unreasonably low and costs excessive.

5.3.2 PROPOSED BACT EMISSION LIMITATIONS

BACT PM/PM_{10} limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-4 and 5-5, respectively. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are shown in Tables 5-6 and 5-7. All determinations are based on the use of clean fuels and good combustion practice.

Because postprocess stack controls for PM_{10} are not appropriate for CTGs, the use of good combustion practices and clean fuels is considered to be BACT. The repowering project CTG 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 CTG will be fired primarily with pipeline quality natural gas. Low-sulfur, low-ash distillate fuel oil will serve as a back-up fuel source. Due to the difficulties associated with stack testing exhaust streams containing very low PM_{10} concentrations and consistent with recent FDEP BACT determinations for CTGs, a visible emissions limit of 10-percent opacity is proposed as a surrogate BACT limit for PM_{10}. Table 5-8 summarizes the PM_{10} BACT emission limit proposed for the repowering project CTG.

5.4 <u>BACT ANALYSIS FOR CO</u>

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).

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

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	2.5 LBS/HR (GAS)	EFFICIENT OPERATION OF THE COM- BUSTION TURBINE	BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0110	SOUTHERN NATURAL GAS	WARD	3/4/98	4/24/98	2-9160 HP GE MODEL MS3002G NATURAL GAS TURBINES	9160 HP	10.95 TPY	FUEL SPEC: NATURAL GAS	BACT-PSD
AL-0120	GENERAL ELECTRIC PLASTICS	BURKVILLE	5/27/98	7/2/98	COMBINED CYCLE (TURBINE AND DUCT BURNER)		0.01 LBS/MMBTU	CLEAN FUEL - NATURAL GAS/HYDROGEN	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW	0.012 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATION	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION OF NATURAL GAS ONLY	BACT-PSD
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	4.3 LB/DAY	NATURAL GAS, AIR INTAKE COOLER	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		0.012 LB/MMBTU	OPACITY LIMIT APPLIES TO LUBE OIL VENTS.	LAER
CO-0017	THERMO INDUSTRIES, LTD.	FT. LUPTON	2/19/92	3/24/95	TURBINE, GAS FIRED, 5 EACH	246 MMBTU/H	25.8 LB/H	FUEL SPEC: NATURAL GAS FIRED	OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 MMBTU/H	9.9 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
CO-0019	COLORADO POWER PARTNERSHIP	BRUSH		7/20/94	TURBINES, 2 NAT GAS & 2 DUCT BURNERS	385 MMBTU/H EACH TURBINE	12.4 T/YR		OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	TURBINE, GAS, 1 EACH	80 MW	0.006 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, GAS, 4 EACH	400 MW	18 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	TURBINE, CG, 4 EACH	400 MW	19 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	33311	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	15.4 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	TURBINE, GAS, 2 EACH	42 MW	0.0065 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0068	ORANGE COGENERATION LP	BARTOW	12/30/93	1/13/95	TURBINE, NATURAL GAS, 2	368.3 MMBTU/H	5 LB/H	GOOD COMBUSTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. 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	WESTBRDOK	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 STATIO	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 STATIO	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-PSO
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	SEE P2 DESC.	COMBUSTION AIR FILTERS	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STATI	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 HOUS	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 COMBUSTIDN 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 1999.

Table 5-5. RBLC PM Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	DIESEL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	0.01 LB/MMBTU (GAS)	FUEL SPECIFICATION	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	DIESEL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.009 LB/MMBTU	COMBUSTION OF CLEAN FUELS	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	DIESEL	TURBINE, OIL, 1 EACH	80 MW	0.025 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	0.025 LB/MMBTU	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	60.6 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	60.6 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		58 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		58 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	0.026 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	0.026 LB/MMBTU	COMBUSTION CONTROL, FUEL SPEC: CLEAN FUEL	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	15 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0076	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	15 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	10 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	15 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	10 LB/H	FUEL SPEC: LOW SULFUR FUEL	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	0.0472 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	0.0472 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	34389	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	0.009 LB/MMBTU	GOOD COMBUSTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	15 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	17 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	5/31/98	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	7 LB/HR (NAT. GAS)	DRY LNB FUEL SPEC: LOW S OIL, GOOD COMBUSTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	0.012 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	0.012 LB/MMBTU	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	0.0156 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	0.0156 LB/M BTU	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	55 LB/HR	CLEAN FUEL	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	55 LB/HR	CLEAN FUEL	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	0.045 GR/DSCF	FUEL SPEC: 0.4 % SULFUR	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	19.7 LB/HR	COMBUSTION DESIGN	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	19.7 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	BACT-OTHER
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH)	67 LB/HR (EACH)	COMBUSTION CONTROL	BACT-PSD
KY-0057	EAST KENTUCKY POWER COOPERATIVE		3/24/93	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	54 LBS/H (EACH)	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	GAS/OIL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	0.05 LB/MMBTU	FUEL SPECIFICATION: NO. 2 LIGHT OIL	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	GAS/OIL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	0.05 LB/MMBTU	FUEL SPECIFICATION: NO. 2 LIGHT OIL	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.005 LB/MMBTU	DLN IN CONJUNCTION WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	17.4 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	GAS/OIL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	0.31 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	36133	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	0.06 LB/MMBTU NAT GAS	.05 % SULFUR OIL #2 IS USED. EMISSION IS FROM EACH 300 MW SYSTEM.	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	DIESEL ENGINE-DRIVEN FIRE PUMP	2.7 MMBTU/H	0.7 LB/HR	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	COMBUSTION TURBINE/GENERATOR	1970 MMBTU/H	10.7 LB/HR GAS	FUEL SELECTION, GOOD COMBUSTION	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	0.26 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1988 MMBTU/H (CTG)	0.0089 LB/MMBTU (NAT GAS)	COMBUSTING NATURAL GAS	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/98	GAS/OIL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	0.26 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	36109	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BURNER	1988 MMBTU/H (CTG)	0.0089 LB/MMBTU (NAT GAS)	NATURAL GAS COMBUSTION	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU/HR	183.5 TPY	NONE	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU/HR	24.5 TPY	NONE	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	12.25 TPY	GOOD COMBUSTION CONTROL	BACT-PSD
MO-0043	UNION ELECTRIC CO	WEST ALTON	5/6/79	10/5/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	622 MM BTU/HR	174 TPY		BACT-PSD
MS-0028	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	4/9/96	8/19/96	DIESEL	COMBUSTION TURBINE, COMBINED CYCLE	1299 MMBTU/HR NAT GAS	8.1 LB/HR, GAS	GOOD COMBUSTION CONTROLS	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	DIESEL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	9 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	17 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (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	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.026 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MW EACH	3.44 LB/H		BACT-PSD
NV-0015	SAGUARO POWER COMPANY	HENDERSON	6/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5 MW	2.5 PPH	COMBUSTION SYSTEM	LAER
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	17 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NV-0031	CSW NEVADA, INC.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	17 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	0.008 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	0.03 LB/MMBTU	COMBUSTION CONTROLS	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/95	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.028 LB/MMBTU, 12 LB/HR	NO CONTROLS	BACT-OTHER
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	0.005 LB/MMBTU, 2.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.1% BY WEIGHT	BACT-OTHER
NY-0062	FULTON COGEN PLANT	FULTON	9/15/94	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500 MMBTU/HR	0.024 LB/MMBTU, 12.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.3% BY WEIGHT	BACT-OTHER
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9 MMBTU/HR	0.024 LB/MMBTU, 5.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.037% BY WEIGHT	BACT-OTHER
NY-0064	INDECK-OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	0.008 LB/MMBTU, 5.00 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.27% BY WEIGHT	BACT-OTHER
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	1/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491 BTU/HR	0.005 LB/MMBTU, 3.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	34101	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	0.006 LB/MMBTU, 2.5 LB/HR	NO CONTROLS	BACT-OTHER
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	SEE NOTE #1	FUEL SPECIFICATION	BACT-OTHER
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	0.005 LB/MMBTU, 3.0 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	DIESEL GENERATOR (EP #00005)	22 MMBTU/HR	0.024 LB/MMBTU, 0.53 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	FIRE PUMP (EP #00007)	1.5 MMBTU/HR	0.2 LB/MMBTU, 0.29 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.15% BY WEIGHT	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	0.008 LB/MMBTU, 5.8 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.15% BY WEIGHT	BACT-OTHER
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	DIESEL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9 MMBTU/HR	0.006 LB/MMBTU, 2.5 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.20% BY WEIGHT	BACT-OTHER
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	DIESEL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1400 MMBTU/HR	0.007 LB/MMBTU, 7.20 LB/HR	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.05% BY WEIGHT	BACT-OTHER
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	DIESEL	GE FRAME 6 GAS TURBINE	424.7 MMBTU/HR	0.006 LB/MMBTU, 2.9 LB/HR	NO CONTROLS	BACT-OTHER
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	DIESEL	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	SEE NOTE #2	FUEL SPEC: SULFUR CONTENT NOT TO EXCEED 0.30% BY WEIGHT	BACT-OTHER
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	GAS/OIL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850 MMBTU/HR	0.012 LB/MMBTU, 10.2 LB/HR	NO CONTROLS	BACT-OTHER
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58 MW	0.0125 LB/MMBTU	FUEL SPEC: USE OF DISTILLATE FUEL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150 MMBTU	0.1 LB/MMBTU*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	450 MMBTU	0.1 LB/MMBTU*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	72 LB/HR	SAME LIMITS APPLY TO PM10.	BACT-PSD
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	55 LB/HR	SAME LIMITS APPLY TO PM10.	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80 MW	15 LB/H		BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1620 MMBTU/H	5.9 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	22 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	12 LB/H FOR GAS	FUEL SPEC: NATURAL GAS AS PRIMARY FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	0.0053 LB/MMBTU	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	0.036 LB/MMBTU	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	33907	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)		74.6 TPY	FUEL SPEC: CLEAN BURN FUEL	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES, COMBINED CYCLE COGEN, GE FRAME 6	123 MW	60 LB/D NG		BACT-PSD
WI-0067	WEPCO, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		12 LBS/HR	GOOD COMBUSTION	BACT-PSD

Source: RBLC 1999.

Table 5-6. 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, 1998.

Table 5-7. Florida BACT PM Emission Limitation Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size		PM Emission Limit		Control Technology
		MW	MMBtu/hr	lb/hr	lb/MMBtu	
08/17/92	Florida Power Corp. Intercession City	93	1,144	15.0	(0.0131)	Combustion design and clean fuels
		186	2,032	17.0	(0.0084)	Combustion design and clean fuels
12/17/92	Auburndale Power Partners	104	1,170	36.8	0.0472	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	40	371	10.0	0.0323	Combustion design and clean fuels
04/09/93	Kissimmee Utility Authority	80	928	15.0	0.0162	Combustion design and clean fuels
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	1,850	17.0	(0.0092)	Combustion design and clean fuels
02/24/94	Tampa Electric Company Polk Power Station	260	1,765	17.0	0.009	Combustion design and clean fuels
07/20/94	Pasco Cogen, Limited	42	406	20.0	0.026	Combustion design and clean fuels
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	991	15.0	(0.0151)	Combustion design and clean fuels
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140		—	—	Combustion design and clean fuels
05/98	City of Tallahassee Purdom Unit 8	160	1,660	—	—	Combustion design and clean fuels
07/10/98	City of Lakeland McIntosh Unit 5	250	2,236	—	—	Combustion design and clean fuels
09/28/98	Florida Power Corp. Hines Energy Complex	165	1,846	44.8	(0.0243)	Combustion design and clean fuels

Note: ( ) = calculated values.

Source: FDEP, 1998.

Table 5-8. Proposed PM_{10} BACT Emission Limit

Emission Source	Proposed PM_{10} BACT Emission Limit* (% Opacity)
GE PG7121 (7EA), CC-1	10

*Maximum rate for all operating scenarios.

Source: ECT, 1999.

Accordingly, CT vendors have had to consider the competing factors involved in NO_x and CO formation to develop units that achieve acceptable emission levels for both pollutants.

5.4.1 POTENTIAL CONTROL TECHNOLOGIES

There are two available technologies for controlling CO from gas turbines: combustion process design and oxidation catalysts.

Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. 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) and water at temperatures lower than would be necessary for oxidation without a catalyst. The operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of CO oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature 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, which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed.

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 technically feasible for combustion devices that are fired with fuels containing appreciable amounts of sulfur.

Technical Feasibility

Both CTG combustor design and oxidation catalyst control systems are considered to be technically feasible for the repowering project CTG. 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 an appreciable amount of sulfur. Increased H_2SO_4 mist emissions will also occur, on a smaller scale, from CTG fired with natural gas and distillate fuel oil. 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., well below the defined PSD significant impact levels for CO). The location of the repowering project (Alachua 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 CO emissions from the repowering project indicate 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 repowering project CTG is projected to have a pressure drop across the catalyst bed of approximately 1.0 inch of water. This pressure drop will result in a 0.2-percent energy penalty due to reduced turbine output power. The reduction in turbine output power (lost power generation) will result in an energy penalty of 1,454,160 kilowatt-hours (kwh) (4,962 million British thermal units [MMBtu]) per year at baseload (83 MW) operation and 8,760 hr/yr operation. This energy penalty is equivalent to the use of 4.73 million cubic feet (ft^3) of natural gas annually based on a nominal natural gas heating value of 1,050 British thermal units per cubic foot (Btu/ft^3). The lost power generation energy penalty, based on a power cost of $0.030/kwh, is $43,625 per year.

5.4.3 ECONOMIC IMPACTS

An economic evaluation of an oxidation catalyst system was performed using the OAQPS factors previously summarized in Table 5-1 and repowering project specific economic factors provided in Table 5-9. Tables 5-10 and 5-11 summarize specific capital and annual operating costs for the oxidation catalyst control system.

Following the first year of operation, base case CTG exhaust CO concentrations for both natural gas- and fuel oil-firing are 20 ppmvd, respectively. Control efficiency for the CO oxidation catalyst system, consistent with efficiencies typically required for oxidation catalyst systems located in nonattainment areas, is assumed to be 90 percent. Base case and controlled CO emission rates are summarized in Table 5-12.

Table 5-9. Economic Cost Factors

Factor	Units	Value
Interest rate	%	8.75
Control system life	Years	10
Catalyst life	Years	
Oxidation		5*
SCR		5*
Electricity cost	$/kwh	0.030
Aqueous NH_3 cost	$/ton	320
Labor costs (base rates)	$/hour	
Operator		28.40
Maintenance		30.61

*Control system vendor guarantee is 3 years of operation or 3.5 years after catalyst delivery, whichever occurs first.

Sources: GRU, 1999.
ECT, 1999.

Table 5-10. Capital Costs for Oxidation Catalyst System

Item	Dollars	OAQPS Factor
Direct Costs		
Purchased equipment	680,000	A
Sales tax	40,800	0.06 × A
Instrumentation	68,000	0.10 × A
Freight	34,000	0.05 × A
Subtotal Purchased Equipment	**$822,800**	**B**
Installation		
Foundations and supports	65,824	0.08 × B
Handling and erection	115,192	0.14 × B
Electrical	32,912	0.04 × B
Piping	16,456	0.02 × B
Insulation for ductwork	8,228	0.01 × B
Painting	8,228	0.01 × B
Subtotal Installation Cost	**$246,840**	
Subtotal Direct Costs	**$1,069,640**	
Indirect Costs		
Engineering	82,280	0.10 × B
Construction and field expenses	41,140	0.05 × B
Contractor fees	82,280	0.10 × B
Start-up	16,456	0.02 × B
Performance test	8,228	0.01 × B
Contingency	24,684	0.03 × B
Subtotal Indirect Costs	**$255,068**	
TOTAL CAPITAL INVESTMENT	**$1,324,708** (TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-11. Annual Operating Costs for Oxidation Catalyst System

Item	Dollars	OAQPS Factor or Basis
Direct Costs		
Catalyst costs		
Replacement (materials and labor)	669,980	Vendor Quote + Labor + Freight + Sales Tax
Credit for used catalyst	(90,000)	15% of Replacement Catalyst
Subtotal Catalyst Costs	**$576,980**	
Annualized Catalyst Costs	**$147,376**	8.75% @ 5 yrs
Energy penalties		
Turbine backpressure	43,625	0.2% Penalty
Subtotal Direct Costs	**$191,001** (TDC)	
Indirect Costs		
Administrative charges	26,494	0.02 × TCI
Property taxes	13,247	0.01 × TCI
Insurance	13,247	0.01 × TCI
Capital recovery	101,362	8.75% @ 10 yrs
Subtotal Indirect Costs	**$154,351**	
TOTAL ANNUAL COST	**$345,352**	

Sources: Engelhard, 1999.
GRU, 1999.
ECT, 1999.

Table 5-12. Summary of CO BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
Oxidation catalyst	4.3	18.9	170.2	1,324,708	345,352	2,029	4,962	Y	Y
Baseline	43.2	189.1	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,760 hr/yr gas-firing and 1,000 hr/yr oil-firing, 20 ppmvd CO gas and oil firing.

Sources: GE, 1999.
Engelhard, 1999.
GRU, 1999.
ECT, 1999.

The cost effectiveness of oxidation catalyst for CO emissions was determined to be $2,029 per ton of CO removed. Based on the high control costs, use of oxidation catalyst technology to control CO emissions is not considered economically feasible. Table 5-12 summarizes results of the oxidation catalyst economic analysis.

5.4.4 PROPOSED BACT EMISSION LIMITATIONS

BACT CO limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-13 and 5-14, respectively. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are shown in Tables 5-15 and 5-16.

The use of oxidation catalyst to control CO from CTGs is typically required only for facilities located in CO nonattainment areas. FDEP gas turbine CO BACT determinations for gas-fired CTGs for the past 5 years range from 9 to 30 ppmvd with an average CO limit of 26 ppmvd. Of the 15 recent FDEP CO BACT determinations for CTGs, 13 determinations established a limit of 20 ppmvd or higher.

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 and distillate fuel oil. 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).

The application of DLN combustors for the GE 7EA CTG results in a trade-off between NO_x and CO emission rates (i.e., controlling NO_x exhaust concentrations to 9 ppmvd at 15 percent oxygen causes an increase in CO emissions compared to a standard combustor). Because ambient CO concentrations in the vicinity of the J.R. Kelly Generating Station would be expected to be well below ambient standards, the reduction in NO_x

Table 5-13. RBLC CO Summary for Natural Gas Fired CTs

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	262.6 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 VB4.3A, 2 SIEMES	260 MW/HRSG PER TURBINE	10 PPM GAS & OIL	PRE-MIX FUEL FAIR TO OPTIMIZE EFFICIENCY ACTUAL	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-0046	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	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	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	64 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	64 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	5/31/96	TURBINE, EXISTING CT RELOCATION TO A NEW PLANT	23 MW	20 PPM @ 15% O2 FULL LD	GOOD COMBUSTION	BACT-PSD
FL-0116	SANTA ROSA ENERGY LLC	NORTHBROOK	12/4/98	4/16/99	TURBINE, COMBUSTION, NATURAL GAS	241 MW			BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GAS	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	10 PPMVD	COMPLETE COMBUSTION	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	12 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED	BACT-PSD
IN-0071	PORTSIDE ENERGY CORP.	PORTAGE	5/13/96	5/31/97	TURBINE, NATURAL GAS-FIRED	63 MEGAWATT	40 LBS/HR	GOOD COMBUSTION AND EMISSIONS NOT TO EXCEED	BACT-PSD
LA-0079	ENRON LOUISIANA ENERGY COMPANY	EUNICE	8/5/91	10/30/91	TURBINE, GAS, 2	39.1 MMBTU/H	60 PPM @ 15% O2	BASE CASE, NO ADDITIONAL CONTROLS	BACT-PSD
LA-0086	INTERNATIONAL PAPER	MANSFIELD	2/24/94	4/17/95	TURBINE/HRSG, GAS COGEN	338 MM BTU/HR TURBINE	165.9 LB/HR	COMBUSTION CONTROL	BACT
LA-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 OPERATI	BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLANT	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	70 LB/HR	COMBUSTION DESIGN AND CONSTRUCTION.	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	198.6 LB/HR	NO ADD-ON CONTROL GOOD COMBUSTION PRACTICE	BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	32842	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	40 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-OTHER
MA-0015	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 PROPE	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 5-13. RBLC CO Summary for Natural Gas Fired CTs (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	6.6 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
NY-0050	SITHE/INDEPENDENCE POWER PARTNERS	OSWEGO	33932	9/13/94	TURBINES, COMBUSTION (4) (NATURAL GAS) (1012 MW)	2133 MMBTU/HR (EACH)	13 PPM	COMBUSTION CONTROLS	BACT-OTHER
NY-0080	PROJECT ORANGE ASSOCIATES	SYRACUSE	12/1/93	3/31/95	GE LM-5000 GAS TURBINE	550 MMBTU/HR	92 LB/HR TEMP > 20F	NO CONTROLS	BACT-OTHER
OH-0218	CNG TRANSMISSION	WASHINGTON COURT HOUS	8/12/92	4/5/95	TURBINE (NATURAL GAS) (3)	5500 HP (EACH)	0.015 G/HP-HR	FUEL SPEC: USE OF NATURAL GAS	OTHER
OR-0010	PORTLAND GENERAL ELECTRIC CO.	BOARDMAN	5/31/94	8/6/97	TURBINES, NATURAL GAS (2)	1720 MMBTU	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	7/7/94	1/27/99	TURBINES, NATURAL GAS (2)	1696 MMBTU/H	15 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	6/3/91	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 1999.

Table 5-14. RBLC CO Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	GAS/OIL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT BURNER	40 MW	22.1 LB/HR	DESIGN	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	GAS/OIL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.04 LB/MMBTU	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	25 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	8/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 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	GAS/OIL	TURBINE, OIL, 2 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	GAS/OIL	TURBINE, OIL, 4 EACH		33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		33 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	78 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	10 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	54 LB/H	COMBUSTION CONTROL	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/96	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	98.4 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	65 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	76 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	33952	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	25 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	2/24/94	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	40 PPMVD	GOOD COMBUSTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/96	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	30 PPMVD	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	54 LB/H	GODD COMBUSTION PRACTICES	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	79 LB/H	GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	6/31/96	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	20 PPM (NAT. GAS)	DRY LNB GOOD COMBUSTION PRACTICES	BACT-PSD
FL-0115	CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	7/10/98	4/16/99	GAS/OIL	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL ALSO	2174 MMBTU/H	25 PPM	GOOD COMBUSTION WITH DLN	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, B	972 MMBTU/H, #2 OIL	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, B	972 MMBTU/H, #2 OIL	9 PPM @ 15% O2	FUEL SPEC: LOW SULFUR FUEL OIL	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD @ FULL LOAD	FUEL SPEC: CLEAN BURNING FUELS	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	30 PPMVD	COMPLETE COMBUSTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	30 PPMVD	COMPLETE COMBUSTION	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	SEE NOTES	GOOD COMBUSTION PRACTICES	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	26.8 LB/HR @ 100% PEAKLD	COMBUSTION DESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	56.4 LB/H @ 75-<100% PKLD	COMBUSTION DESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	181 LB/H @ 50-<75% PKLD	COMBUSTION OESIGN	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/96	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	475.6 LB/H @ 25-<50% PKLD	COMBUSTION DESIGN	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING STA	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	26.9 LB/HR	COMBUSTION TECHNOLOGY/DESIGN	BACT-OTHER
IN-0053	PSI ENERGY, INC. WABASH RIVER STATION	WEST TERRE HAUTE	5/27/93	7/20/94	GAS/OIL	COMBINED CYCLE SYNGAS TURBINE	1775 MMBTU/HR	15 LESS THAN PPM	OPERATION PRAC. AND GOOD COMB,SYNGAS TURBINE	BACT-PSD
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	33673	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH)	75 LB/HR (EACH)	COMBUSTION CONTROL	BACT-PSD
KY-0057	EAST KENTUCKY POWER COOPERATIVE		3/24/93	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	75 LBS/H (EACH)	PROPER COMBUSTION TECHNIQUES	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL 501G	2534 MMBTU/H	0.07 LB/MMBTU	DLN IN CONJ. WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	14.3 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	DIESEL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	0.95 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	12/4/98	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	5 PPM @ 15% O2 (NAT G)	0.05% S #2 IS USED. EACH 300 MW SYSTEM.	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	34471	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	1290 TPY	NONE	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	120 TPY	NONE	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	427.5 TPY	GOOD COMBUSTION CONTROL	BACT-PSD
MO-0043	UNION ELECTRIC CO.	WEST ALTON	6/6/79	10/6/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTION TURBINE	622 MM BTU/HR	463 TPY		BACT-PSD
MS-0028	SOUTH MISSISSIPPI ELECTRIC POWER ASSOC.	MOSELL	4/9/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, COMBINED CYCLE	1299 MMBTU/HR NAT GAS	26.3 PPM @ 15% O2, GAS	GOOD COMBUSTION CONTROLS	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATION	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	60 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	80 LB/HR	COMBUSTION CONTROL	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	81 LB/HR	COMBUSTION CONTROL	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	GAS/OIL	TURBINE, KEROSENE FIRED	585 MMBTU/HR	0.063 LB/MMBTU	CATALYTIC OXIDATION	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.06 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.06 LB/MMBTU	TURBINE DESIGN	BACT-OTHER
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MW EACH	15.2 LB/H		BACT
NV-0015	SAGUARO POWER COMPANY	HENDERSON	8/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5 MW	9 PPH	CONVERTER (CATALYTIC)	BACT-PSD
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	77 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NV-0031	CSW NEVADA, INC.	MOAPA	6/10/94	3/24/96	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	83 LB/HR	FUEL SPEC: NATURAL GAS	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	8/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	5 PPM @ 15% O2		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	0.25 LB/MMBTU		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	5 PPM @ 15% O2		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	0.25 LB/MMBTU		LAER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	DIESEL	FIRE PUMP (DIESEL)	1.3 MMBTU/HR	0.71 LB/MMBTU	COMBUSTION CONTROL	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	8.5 PPM	COMBUSTION CONTROL	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILITY	BEAVER FALLS	33917	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (79MW)	650 MMBTU/HR	9.5 PPM	COMBUSTION CONTROLS	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/86	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	0.026 LB/MMBTU, 11 LB/HR	NO CONTROLS	BACT-OTHER
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #00001	451 MMBTU/HR	36 PPM, 33 LB/HR	BAFFLE CHAMBER	SEE NOTE #4
NY-0062	FULTON COGEN PLANT	FULTON	9/15/94	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500 MMBTU/HR	107 PPM, 120 LB/HR	NO CONTROLS	BACT-OTHER
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9 MMBTU/HR	0.181 LB/MMBTU	CATALYTIC OXIDIZER	BACT
NY-0064	INDECK OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	10 PPM, 10.00 LB/HR	NO CONTROLS	BACT-OTHER
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	1/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491 BTU/HR	10 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	5/12/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	40 PPM	NO CONTROLS	BACT-OTHER
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	0.02 LB/MMBTU, 10 LB/HR	NO CONTROLS	BACT-OTHER
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	9 PPM, 11.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	DIESEL GENERATOR (EP #00005)	22 MMBTU/HR	0.371 LB/MMBTU, 8.27 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	FIRE PUMP (EP #00007)	1.5 MMBTU/HR	2.88 LB/MMBTU, 4.23 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	9.5 PPM	NO CONTROLS	BACT-OTHER
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	GAS/OIL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9 MMBTU/HR	10 PPM	NO CONTROLS	BACT-OTHER
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	GAS/OIL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 00001&2)	1400 MMBTU/HR	10 PPM, 29.0 LB/HR		BACT-OTHER
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE	424.7 MMBTU/HR	10 PPM, 10.0 LB/HR	NO CONTROLS	BACT-OTHER

Table 5-14. RBLC CO Summary for Distillate/Multiple Fuel Fired CTGs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates		Fuel	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
			Issuance	Update	Type					
NY-0077	INDECK-YERKES ENERGY SERVICES	TONAWANDA	6/24/92	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE (EP #00001)	432.2 MMBTU/HR	10 PPM, 10 LB/HR	NO CONTROLS	BACT-OTHER
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	GAS/OIL	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	48 PPM, 12.6 LB/HR		BACT-OTHER
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	DIESEL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850 MMBTU/HR	10 PPM, 19.7 LB/HR	NO CONTROLS	BACT-OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	DIESEL	GENERATORS, DIESEL, 2	1135 KW EACH	7.9 LB/H EACH		OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150 MMBTU	0.0055 LB/MMBTU (GAS)*	COMBUSTION	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	460 MMBTU	0.0055 LB/MMBTU (NAT GAS)*	COMBUSTION	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	34911	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	20 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES.	BACT-PSD
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYCLE EACH	248 MW	104 LB/HR	IMPLEMENT GOOD COMBUSTION PRACTICES.	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80 MW	60 LB/H		BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	702 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	414 LB/H	PROPER OPERATION TO ACHIEVE GOOD COMBUSTION	BACT-PSD
SC-0038	GENERAL ELECTRIC GAS TURBINES	GREENVILLE	4/19/96	8/19/96	GAS/OIL	I.C. TURBINE	2700 MMBTU/HR	27169 LB/HR	GOOD COMBUSTION PRACTICES TO MIN. EMISSIONS	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	50 PPM FOR GAS	GOOD COMBUSTION TECHNIQUES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	1331.13 X10(7) SCF/Y NAT GAS	249.9 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	7.44 X10(7) GPY FUEL OIL	249.9 TOTAL TPY	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) [EACH WITH A SF]	1.51 X10(9) BTU/HR N.GAS	57 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) [EACH WITH A SF]	1.36 X10(9) BTU/H #2 OIL	68 LBS/HR/UNIT	GOOD COMBUSTION PRACTICES	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N. GAS	11 LBS/HR	GOOD COMBUSTION	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2 OIL	11 LBS/HR	GOOD COMBUSTION	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)		48.2 TPY	GOOD COMBUSTION	BACT-PSD
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	9/15/93	5/7/97	GAS/OIL	TURBINE, COMBUSTION, SIEMENS MODEL V84.2, 3	10.2 X109 SCF/YR NAT GAS	26 LB/HR	GOOD COMBUSTION OPERATING PRACTICES	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PROJECT	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES, COMBINED CYCLE COGEN, GE FRAME 6	123 MW	10 PPMDV @ 15% O2		BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		25 LBS/HR (SEE NOTES)		BACT-PSD

Source: RBLC 1999.

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

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	30	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	15	Good combustion
02/21/94	Polk Power Partners	84	25	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	25	Good combustion
07/20/94	Pasco Cogen, Limited	42	28	Good combustion
03/07/95	Orange Cogeneration, L.P.	39	30	Good combustion
06/01/95	Panda-Kathleen	75	25	Good combustion
09/28/95	City of Key West	23	20	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	20	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	25	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	25	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	25	Good combustion
11/25/98	Florida Power & Light Fort Myers Repowering	170	12	Good combustion
12/04/98	Santa Rosa Energy Center	167	9	Good combustion
			24 (with duct burner)	Good combustion

Source: FDEP, 1998.

Table 5-16. Florida BACT CO Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	CO Emission Limit (ppmvd)	Control Technology
04/09/93	Kissimmee Utility Authority	40	63	Good combustion
04/09/93	Kissimmee Utility Authority	80	20	Good combustion
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	30	Good combustion
02/21/94	Polk Power Partners	84	35	Good combustion
02/24/94	Tampa Electric Company Polk Power Station	260	40	Good combustion
07/20/94	Pasco Cogen, Limited	42	18	Good combustion
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	25	Good combustion
05/98	City of Tallahassee Purdom Unit 8	160	90	Good combustion
07/10/98	City of Lakeland McIntosh Unit 5	250	90	Good combustion
09/28/98	Florida Power Corp. Hines Energy Complex	165	30	Good combustion

Source: FDEP, 1998.

emissions is considered to have a greater environmental benefit and would more than compensate for the higher CO emission rates associated with DLN technology.

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 all CTGs permitted within the past 5 years. Following the first year of operation, at baseload operation for both natural gas and distillate fuel oil firing, maximum CO exhaust concentration and hourly mass emission rate from the CTG will be 20 ppmvd and 43 lb/hr (at ISO conditions). These CO exhaust concentrations and emission rates are consistent with recent FDEP BACT determinations for CTGs (e.g., City of Tallahassee Purdom Unit 8 and Lakeland Utilities McIntosh Unit 5). Table 5-17 summarizes the CO BACT emission limits proposed for the repowering project.

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 bound fuel nitrogen (fuel NO_x). 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 ammonia (NH_3). 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

Table 5-17. Proposed CO BACT Emission Limits

Emission Source	Proposed CO BACT Emission Limits lb/hr*	ppmvd
GE PG7121 (7EA) CTG, CC-1† (Natural Gas-Fired)	54	25
GE PG7121 (7EA) CTG, CC-1 (Natural Gas-Fired)	43	20
GE PG7121 (7EA) CTG, CC-1 (Distillate Fuel Oil-Fired)	43	20

*At ISO conditions.
†First year operation.

Sources: GE, 1999.
ECT, 1999.

NO_x arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of FBN to NO_x depends on the bound nitrogen content of the fuel. In contrast to thermal NO_x, fuel NO_x formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO_x emissions. For this reason, the gas turbine NSPS (Subpart GG) contains an allowance for FBN (see Table 5-2). NO_x emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N_2); however, the molecular nitrogen found in natural gas does not contribute significantly to fuel NO_x formation. Typically, natural gas contains a negligible amount of FBN.

5.5.1 POTENTIAL CONTROL TECHNOLOGIES

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

Combustion Process Modifications:

- Water or steam injection and standard combustor design.
- Water or steam injection and advanced combustor design.
- DLN combustor design.

Postcombustion Exhaust Gas Treatment Systems:

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

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

Water or Steam Injection and Standard Combustor Design

Injection of water or steam into the primary combustion zone of a CTG reduces the formation of thermal NO_x by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to: (a) vaporize the water (latent heat of vaporization), and (b) raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 pounds of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO_x.

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

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

Water or Steam Injection and Advanced Combustor Design

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

Dry Low-NO_x Combustor Design

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

- Primary Mode—Fuel supplied to first stage only at turbine loads from 0 to 35 percent. Combustor burns with a diffusion flame with quiet, stable operation. This mode is used for ignition, warm-up, acceleration, and low-load operation.
- Lean-Lean Mode—Fuel supplied to both stages with flame in both stages at turbine loads from 35 to 50 percent. Most of the secondary fuel is premixed with air. Turbine loading continues with a flame present in both fuel stages. As load is increased, CO emissions will decrease, and NO_x levels will increase. Lean-lean operation will be maintained with increasing turbine load until a preset combustor fuel-to-air ratio is reached when transfer to premix operation occurs.
- Secondary Mode (Transfer to Premix)—At 60-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 60 to 100 percent. Flame is present in the second stage only.

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

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

Current DLN combustor technology can typically achieve a NO_x exhaust concentration of 15 ppmvd or less using natural gas fuel.

__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 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 oxygen) conditions. NSCR technology has been applied to automobiles and stationary reciprocating engines.

Selective Catalytic Reduction

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

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

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

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

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

As was the case for SNCR, reaction temperature is critical for proper SCR operation. The optimum temperature range for conventional SCR operation is 600 to 750°F. Below this temperature range, reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of NH_3 will take place resulting in an increase in NO_x emissions. Specially formulated, high-temperature zeolite catalysts have recently been developed that function at exhaust stream temperatures up to a maximum of approximately 1,025°F. The exhaust temperature range for the GE 7EA simple cycle unit is 974 to 1,100°F (gas firing) and 968 to 1,100°F (oil firing). Accordingly, the simple-cycle CTG exhaust temperature would need to be reduced to an acceptable level prior to treatment by a hot SCR control system. 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 exclusively offered by Goal Line Environmental Technologies (GLET). GLET is a partnership formed by Sunlaw Energy Corporation and Advanced Catalyst Systems, Inc.

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

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

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

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

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

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

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

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

Since the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers. Each catalyst section is equipped with a set of upstream and downstream louvers. During the regeneration cycle, these louvers close and valves open allowing fresh regeneration gas to enter and spent regeneration gas to exit the catalyst section being regenerated. At any given time, 75 percent of the catalyst sections will be in the oxidation/absorption cycle, while 25 percent will be in regeneration mode. A regeneration cycle is typically set to last for 3 to 5 minutes.

Regeneration gas is produced by reacting natural gas with oxygen present in ambient air. The $SCONO_x$™ system uses a gas generator produced by Surface Combustion. This unit uses a two-stage process to produce hydrogen and CO_2. In the first stage, natural gas and ambient air are reacted across a partial oxidation catalyst at 1,900°F to form CO and hydrogen. Steam is added and the gas mixture then passed across a low temperature shift catalyst, forming CO_2 and additional hydrogen. The resulting gas stream is diluted to less than 4 percent hydrogen using steam or another inert gas. The regeneration gas reactions are:

$$CH_4 + \frac{1}{2} O_2 + 1.88\, N_2 \rightarrow CO + 2\, H_2 + 1.88\, N_2 \qquad (9)$$

$$CO + 2\, H_2 + H_2O + 1.88\, N2_2 \rightarrow CO_2 + 3\, H_2 + 1.88\, N_2 \qquad (10)$$

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 $SCONO_x$™ systems installed in locations of the HRSG above 500°F, a separate regeneration gas generator is not required. Instead, regeneration gas is produced by introducing natural gas directly across the $SCONO_x$™ catalyst, which reforms the natural gas.

The $SCONO_x$™ system catalyst is subject to reduced performance and deactivation due to exposure to sulfur oxides. For this reason, an additional catalytic oxidation/absorption system ($SCOSO_x$™) to remove sulfur compounds is installed upstream of the $SCONO_x$™ catalyst. 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:

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

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

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

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

Utility materials need for the operation of the $SCONO_x$™ 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, combined-cycle 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 $SCONO_x$™ control system was installed at 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.

<u>Technical Feasibility</u>

All of the combustion process modification technologies mentioned (water or steam injection and standard combustor design, water or steam injection and advanced combustor design, and DLN combustor design) would be feasible for the repowering project CTG. 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 oxygen) environment. Due to high excess air rates, the oxygen content of CT exhaust gases is typically 13 percent.

The $SCONO_x$™ control technology is not technically feasible for simple-cycle mode operation because the temperature required for this technology (between 300 to 700°F) is well below the 1,100°F typically occurring for simple-cycle CTG exhaust gas streams. The $SCONO_x$™ control technology is also not considered technically feasible for combined-cycle mode operation because the technology has not been commercially demonstrated on a large CTG. The CTG planned for the repowering project, a GE PG7121 (7EA) unit, has a nominal generation capacity of 83 MW. Accordingly, the repowering project CTG is over three times larger than the nominal 25-MW GE LM2500 used at the Sunlaw Energy Corporation Los Angeles facility. Technical problems associated with scale-up of the $SCONO_x$™ technology are unknown. 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 repowering project CTG was confined to advanced DLN combustors (natural gas firing), water injection (distillate fuel oil firing), and the application of postcombustion conventional SCR control technologies. The following sections provide information regarding energy, environmental, and economic impacts and proposed BACT limits for NO_x.

5.5.2 ENERGY AND ENVIRONMENTAL IMPACTS

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

The installation of SCR technology will cause an increase in back pressure on the CTG due to the pressure drop across the catalyst bed. Additional energy would be needed for the pumping of aqueous NH_3 from storage to the injection nozzles and generation of steam for NH_3 vaporization. A SCR control system for the repowering project CTG is projected to have a pressure drop across the catalyst bed of approximately 3.0 inches of water. This pressure drop will result in a 0.6-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 4,362,480 kwh (14,885 MMBtu) per year at baseload (83 MW) operation and 8,760 hr/yr operation. This energy penalty is equivalent to the use of 14.18 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 $130,874 per year.

There are no significant adverse environmental effects due to the use of advanced DLN combustor technology. In contrast, application of SCR technology would result in the following adverse environmental impacts:

- NH_3 emissions due to *ammonia slip*; NH_3 emissions are estimated to total 25 tpy (at baseload and 59°F ambient temperature) for a SCR design NH_3 slip rate of 5 ppmvd. However, NH_3 slip can increase significantly during start-ups, upsets, or failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 ppmv or greater have been measured. Since the odor threshold of NH_3 is 20 ppmv, releases of NH_3 during upsets or malfunctions have the potential to cause ambient odor problems. NH_3 also acts as an irritant to human tissue. Depending on the concentration and duration of exposure, NH_3 can cause eye, skin, and mucous membrane irritation. These effects can vary from minor irritation to severe damage. Contact of the skin or mucosa with liquid NH_3 or a high vapor concentration can result in burns or obstructed breathing.
- Ammonium bisulfate and ammonium sulfate particulate emissions due to the reaction of NH_3 with SO_3 present in the exhaust gases; total PM/PM_{10} emissions would increase by approximately 50 percent.
- A public risk due to potential leaks from the storage of large quantities of NH_3; NH_3 has been designated an *Extremely Hazardous Substance* under the federal Superfund Amendment and Reauthorization Act Title III regulations.
- Disposal of spent catalyst that may be considered hazardous due to heavy metal contamination; vanadium pentoxide is an active component of a typical SCR catalyst and is listed as a hazardous chemical waste under Resource Conservation and Recovery Act Regulations 40 CFR 261.30. As a potential hazardous waste, spent catalyst may have to be transported and disposed in a hazardous waste landfill. In addition, facility workers could be exposed to high levels of vanadium pentoxide particulates during catalyst handling.

Furthermore, the application of SCR technology would present potential public health concerns due to the risks of storing and transporting large quantities of NH_3 in an urbanized area such as the project area. Figure 5-1 provides a photographic depiction of land use surrounding the project area. Existing land uses in the surrounding area are primarily

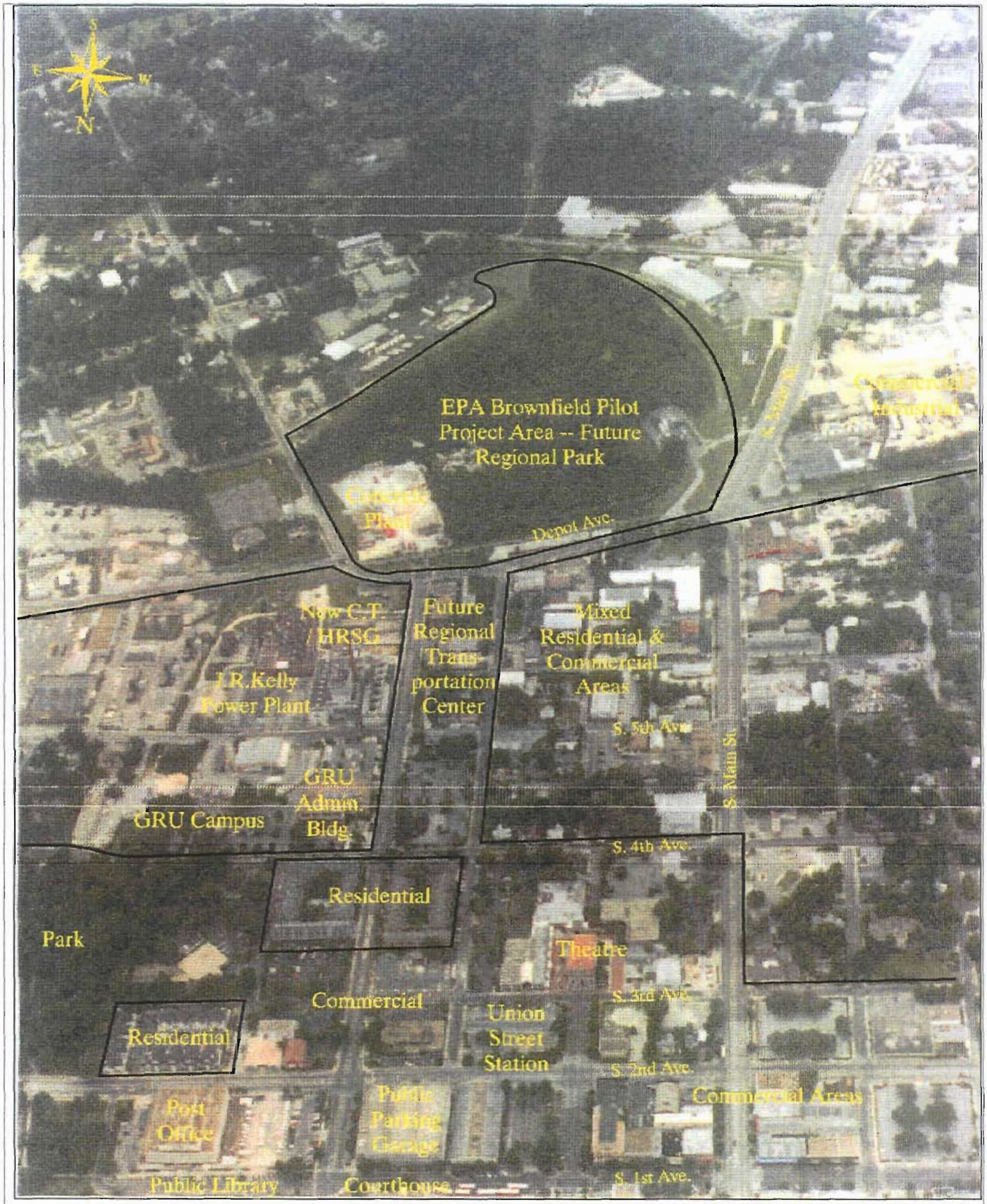


FIGURE 5-1.
LAND USE PHOTOGRAPH

Source: GRU, 1999.

GRU

residential to the north and east, mixed residential/commercial to the west, and industrial to the south. Several redevelopment projects have been proposed or are currently in progress that will increase use of the area by the public. These projects include a new regional transportation center to the west and directly across the street from the repowering project, an EPA Brownfield pilot project that envisions the creation of a regional park on the large tract of land immediately south of the repowering project, and the Union Street Station: a multistory commercial/residential complex approximately 3 blocks northwest of the project site.

5.5.3 ECONOMIC IMPACTS

An assessment of economic impacts was performed by comparing control costs between a baseline case of advanced DLN combustor technology and baseline technology with the addition of SCR controls. Baseline technology is expected to achieve NO_x exhaust concentrations of 9.0 and 42 ppmvd at 15-percent oxygen for natural gas and distillate fuel oil firing, respectively. SCR technology was premised to achieve NO_x concentrations of 3.5 and 16.3 ppmvd at 15-percent oxygen for natural gas and distillate fuel oil firing, respectively. The NO_x concentration of 3.5 ppmvd is representative of recent LAER determinations made in California for natural gas-fired CTGs equipped with DLN combustor technology and SCR controls. As supplied by GE, the PG7121 (7EA) unit is equipped with duel-fuel low-NO_x combustors. GE offer no other option with respect to combustor type or design.

The cost impact analysis was conducted using the OAQPS factors previously summarized in Table 5-1 and repowering project-specific economic factors provided in Table 5-9. Emission reductions were calculated assuming baseload operation for 7,760 and 1,000 hr/yr (for natural gas and distillate fuel oil firing, respectively) at an annual average ambient temperature of 59°F. Tables 5-18 and 5-19 summarize specific capital and annual operating costs for the SCR control system, respectively.

Cost effectiveness for the application of SCR technology to the repowering project CTG was determined to be \$5,027 per ton of NO_x removed. This control cost is considered economically unreasonable. Table 5-20 summarizes results of the NO_x BACT analysis.

Table 5-18. Capital Costs for SCR System

Item	Dollars		OAQPS Factor
<u>Direct Costs</u>			
Purchased equipment	710,000	(A)	
Instrumentation	76,400		0.10 × A
Sales tax	45,600		0.06 × A
Freight	38,000		0.05 × A
Subtotal Purchase Equipment	**$919,600**		B
Installation			
Foundations and supports	73,568		0.08 × B
Handling and erection	128,744		0.14 × B
Electrical	36,784		0.04 × B
Piping	18,392		0.02 × B
Insulation for ductwork	9,196		0.01 × B
Painting	9,196		0.01 × B
Subtotal Installation Cost	**$275,880**		
Subtotal Direct Costs	**$1,195,480**		
<u>Indirect Costs</u>			
Engineering	91,960		0.10 × B
Construction and field expenses	45,980		0.05 × B
Contractor fees	91,960		0.10 × B
Start-up	18,392		0.02 × B
Performance test	9,196		0.01 × B
Contingency	27,588		0.03 × B
Subtotal Indirect Costs	**$285,076**		
TOTAL CAPITAL INVESTMENT	**$1,480,556**	(TCI)	

Sources: Engelhard, 1999.
ECT, 1999.

Table 5-19. Annual Operating Costs for SCR System

Item	Dollars		OAQPS Factor
Direct Costs			
Labor and material costs			
Operator	15,549	(A)	@ $28.40/hr
Supervisor	2,332		0.15 × A
Maintenance			
Labor	16,759	(B)	@ $30.61/hr
Materials	16,759		1.00 × B
Subtotal Labor, Material, and Maintenance Costs	**$51,399**	**(C)**	
Catalyst costs			
Replacement (materials and labor)	$428,500		Vendor Quote + Labor + Freight + Sales Tax
Annualized Catalyst Costs	**$109,450**		8.75% @ 5 yrs
Raw materials and utilities			
Electricity	9,497		
Aqueous NH_3	77,899		
Subtotal Raw Materials and Utilities	**$87,396**		
Energy penalties			
Turbine backpressure	130,874		0.6% Penalty
Subtotal Direct Costs	**$379,119**	(TDC)	
Indirect Costs			
Overhead	30,840		0.60 × C
Administrative charges	29,611		0.02 × TCI
Property taxes	14,806		0.01 × TCI
Insurance	14,806		0.01 × TCI
Capital recovery	168,296		8.75% @ 5 yrs
Subtotal Indirect Costs	**$258,358**		
TOTAL ANNUAL COST	**$637,478**		

Sources: Engelhard, 1999.
GRU, 1999.
ECT, 1999.

Table 5-20. Summary of NO_x BACT Analysis

	Emission Impacts			Economic Impacts			Energy Impacts	Environmental Impacts	
Control Option	Emission Rates lb/hr	Emission Rates tpy	Emission Reduction (tpy)	Installed Capital Cost ($)	Total Annualized Cost ($/yr)	Cost Effectiveness Over Baseline ($/ton)	Increase Over Baseline (MMBtu/yr)	Toxic Impact (Y/N)	Adverse Envir. Impact (Y/N)
SCR	18.4	80.4	126.8	1,480,556	637,478	5,027	14,885	Y	Y
Baseline	47.3	207.2	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Basis: One GE PG7121 (7EA) CTG, 100-percent load for 7,760 hr/yr gas-firing and 1,000 hr/yr oil-firing.

Sources: GE, 1999.
GRU, 1999.
ECT, 1999.

5.5.4 PROPOSED BACT EMISSION LIMITATIONS

BACT NO_x limits obtained from the RBLC database for natural gas- and distillate fuel oil-fired CTGs are provided in Tables 5-21 and 5-22, respectively. Recent Florida BACT determinations for natural gas- and distillate fuel oil-fired CTGs are shown in Tables 5-23 and 5-24.

FDEP natural gas-fired CTG NO_x BACT determinations for the past 5 years range from 12 to 25 ppmvd at 15-percent oxygen with an average NO_x limit of 15 ppmvd at 15-percent oxygen. Of the ten most recent FDEP NO_x BACT determinations for CTG, seven determinations established a limit of 15 ppmvd or higher.

At baseload operation with natural gas firing, maximum NO_x exhaust concentration and hourly mass emission rate from the CTG will be 9.0 ppmvd and 35.0 lb/hr, respectively, based on the application of DLN combustors. At baseload operation with distillate fuel oil firing, maximum NO_x exhaust concentration and hourly mass emission rate from the CTG will be 42 ppmvd and 179.0 lb/hr, respectively, based on the use of wet injection. Table 5-25 summarizes the NO_x BACT emission limits proposed for the repowering project. NO_x emission rates proposed as BACT for the repowering project CTG are consistent with recent FDEP BACT determinations.

5.6 SUMMARY OF PROPOSED BACT EMISSION LIMITS

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

Table 5-21. RBLC NO_x Summary for Natural Gas Fired CTs

RBLC ID	Facility Name	City	Permit Dates Issuance	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	0.58 GM/HP HR	AIR-TO-FUEL RATIO CONTROL, DLN COMBUSTION	BACT-PSD
AL-0089	SOUTHERN NATURAL GAS COMPANY-SELMA COMPRESS	SELMA	12/4/96	12/18/96	9160 HP GE MS3002G NATURAL GAS FIRED TURBINE		53 LB/HR		BACT-PSD
AL-0096	MEAD COATED BOARD, INC.	PHENIX CITY	3/12/97	5/31/97	COMBINED CYCLE TURBINE (25 MW)	568 MMBTU/HR	25 PPMVD@ 15% O2 (GAS)		BACT-PSD
AL-0109	SOUTHERN NATURAL GAS	AUBURN	3/2/98	4/24/98	9160 HP GE MODEL M53002G NATURAL GAS FIRED TURBINE	9160 HP	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	9160 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 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)		0.07 LBS/MMBTU COMBINED	DLN ON TURBINE AND LOW NOX BURNER ON DB	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATIO	THEODORE	3/16/99	4/20/99	170 MW TURBINE W/ DUCT BURNER, HR BOILER, SCR	170 MW	0.013 LB/MMBTU	DLN COMBUSTOR IN CT, LNB IN DUCT BURNER, SCR	BACT-PSD
AL-0128	ALABAMA POWER COMPANY - THEODORE COGENERATIO	THEODORE	3/16/99	4/20/99	220 MMBTU/HR BOILER	220 MMBTU/HR	0.053 LB/MMBTU	LNB AND FLUE GAS RECIRCULATION	BACT-PSD
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 HP	84.9 PPM @ 15% O2	LEAN BURN	NSPS
AZ-0010	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 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	5500 HP	85.1 PPM @ 15% O2	FUEL SPEC: LEAN FUEL MIX	NSPS
AZ-0011	EL PASO NATURAL GAS		10/25/91	3/24/95	TURBINE, GAS, SOLAR CENTAUR H	5500 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	12000 HP	225 PPM @ 15% O2	LEAN BURN	BACT-PSD
AZ-0012	EL PASO NATURAL GAS		10/18/91	7/20/94	TURBINE, NAT. GAS TRANSM., GE FRAME 3	12000 HP	42 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
CA-0418	SOUTHERN CALIFORNIA GAS	WHEELER RIDGE	10/29/91	8/4/93	TURBINE, GAS-FIRED	47.64 MMBTU/H	8 PPMVD @ 15% O2	HIGH TEMPERATURE SCR	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	5500 HP	8 PPM @ 15% O2	HIGH TEMP SELECT. CAT. REDUCTION	BACT-PSD
CA-0544	GOAL LINE, LP ICEFLOE	ESCONDIDO	33911	8/4/94	TURBINE, COMBUSTION (NATURAL GAS) (42.4 MW)	386 MMBTU/HR	5 PPMVD @ 15% OXYGEN	H2O INJECT. & SCR W/ AUTOMATIC NH3 INJECT.	BACT-OTHER
CA-0613	UNOCAL	WILMINGTON	7/18/89	12/5/94	TURBINE, GAS (SEE NOTES)		9 PPM @ 15% O2	SCR, WATER INJECTN	BACT-OTHER
CA-0768	NORTHERN CALIFORNIA POWER AGENCY	LODI	10/2/97	3/16/98	GE FRAME 5 GAS TURBINE	325 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX BURNERS	LAER
CA-0774	SOUTHERN CALIFORNIA GAS COMPANY	WHEELER RIDGE	5/14/97	3/16/98	VARIABLE LOAD NATURAL GAS FIRED TURBINE COMPRESSOR	50.1 MMBTU/HR	25 PPMVD @ 15% O2	DRY LOW NOX COMBUSTOR	LAER
CA-0793	TEMPO PLASTICS	VISALIA	12/31/96	4/23/98	GAS TURBINE COGENERATION UNIT		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-0845	SACRAMENTO POWER AUTHORITY CAMPBELL SOUP	SACRAMENTO	8/19/94	4/13/99	TURBINE, GAS , COMBINED CYCLE, SIEMENS V84.2	1257 MMBTU/H	3 PPMVD @ 15% O2	SCR AND DRY LOW NOX CO MBUSTION	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING	ELK GROVE	7/23/93	4/13/99	TURBINE, GAS, COMBINED CYCLE, GE LM6000	450 MMBTU/H	5 PPMVD @ 15% O2	SCR AND WATER INJECTION	BACT
CA-0846	CARSON ENERGY GROUP & CENTRAL VALLEY FINANCING	ELK GROVE	7/23/93	4/13/99	TURBINE, GAS, SIMPLE CYCLE, GE LM6000	450 MMBTU/H	5 PPMVD @ 15% O2	SCR AND WATER INJECTION	BACT
CA-0853	KERN FRONT LIMITED	BAKERSFIELD	11/4/86	4/19/99	TURBINE, GAS, GENERAL ELECTRIC LM-2500	25 MW	96.96 LB/D	WATER INJECTION AND SCR	BACT-OTHER
CA-0858	BEAR MOUNTAIN LIMITED	BAKERSFIELD	8/19/94	4/19/99	TURBINE, GE, COGENERATION, 48 MW	48 MW	3.6 PPMVD @ 15% O2	STEAM INJECTION AND SCR	BACT-OTHER
CA-0863	SUNLAW COGEN. (FEDERAL COLD STORAGE COGENERATI	VERNON	1/15/94	4/19/99	TURBINE, NATURAL GAS FIRED, COMBINED CYCLE AND COG	28 MW	186817 LB/YR	WATER INJECTION AND SCONOX (MOD 2)	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	DRY LOW NOX TECH.	BACT-PSD
CO-0018	BRUSH COGENERATION PARTNERSHIP	BRUSH		7/20/94	TURBINE	350 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 MMBTU/H EACH T	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #1, GE FRAME 6	33 MW	25 PPM @ 15% O2	WATER INJECTION	OTHER
CO-0020	CIMARRON CHEMICAL	JOHNSTOWN	3/25/91	7/20/94	TURBINE #2, GE FRAME 6	33 MW	9 PPM @ 15% O2	SCR	OTHER
CO-0021	NORTHWEST PIPELINE CORPORATION	LA PLATA B" STATION"	5/29/92	7/20/94	TURBINE, SOLAR TAURUS	45 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 MMBTU/HR	22 PPM @ 15% O2	DRY LOW NOX COMBUSTION	BACT-OTHER.
CO-0037	COLORADO SPRINGS UTILITIES	FOUNTAIN	1/4/99	4/19/99	TURBINE, COMBINE, NATURAL GAS FIRED	30 MW EACH	15 PPMVD ABOVE 70% LOAD	POLLUTION PREVENTION BUILT INTO EQUIPMENT.	BACT-PSD
CT-0130	BRIDGEPORT ENERGY, LLC	BRIDGEPORT	6/29/98	1/21/99	TURBINES, COMBUSTION MODEL V84.3A, 2 SIEMES	260 MW/HRSG PER TU	6 PPM NAT. GAS	DRY LOW NOX BURNER WITH SCR	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	WET INJECTION	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	33444	3/24/95	TURBINE, GAS, 1 EACH	80 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 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 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/96	TURBINE, GAS, 4 EACH	400 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 MW	42 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	TURBINE, GAS, 4 EACH	240 MW	42 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	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	25 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	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 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	TURBINE, GAS, 4 EACH	35 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0059	SEMINOLE FERTILIZER CORPORATION	BARTOW	3/17/91	5/14/93	TURBINE, GAS	26 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	1614.8 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	1614.8 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0074	FLORIDA GAS TRANSMISSION	PERRY	9/27/93	4/11/94	TURBINE, GAS	131.59 MMBTU/H	25 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	869 MMBTU/H	15 PPM @ 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	TURBINE, NATURAL GAS	367 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	1214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	TURBINE,GAS	1214 MMBTU/H	15 PPMVD @ 15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK CDUNTY SITE	BARTOW	2/25/94	1/13/95	TURBINE, NATURAL GAS (2)	1510 MMBTU/H	12 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)	1510 MMBTU/H	12 PPMVD @15 % O2	DRY LOW NOX COMBUSTOR	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	34800	5/29/95	SIMPLE CYCLE COMBUSTION TURBINE, GAS/NO 2 OIL B-UP	74 MW	15 PPM AT 15% OXYGEN	DRY LOW NOX BURNERS GE FRAME UNIT	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	15 PPM AT 15% OXYGEN	DLN	BACT-PSD
FL-0102	PANDA-KATHLEEN, L.P.	LAKELAND	6/1/95	5/20/96	COMBINED CYCLE COMBUSTION TURBINE (TOTAL 115MW)	75 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 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 MW	9.8 PPM@15%O2 DB ON	DRY LOW NOX BURNER	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, 8	1032 MMBTU/H, NAT GA	25 PPM @ 15% O2	MAX WATER INJECTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	TURBINES, B	1032 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)	1817 M BTU/HR	25 PPM @ 15% O2	MAXIMUM WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	TURBINE, GAS FIRED (2 EACH)	1817 M BTU/HR	25 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 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 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	COMBUSTION TURBINE (2), NATURAL GAS	116 MW	9 PPMVD	DRY LOW NOX BURNER WITH SCR	BACT-PSD

Table 5-21. RBLC NO_x Summary for Natural Gas Fired CTs (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
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 MM BTU/HR TURBI	25 PPMV 15% O2 TURBINE	DLN/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	9 PPMV	DLN DESIGN AND CONTROL	LAER
LA-0091	GEORGIA GULF CORPORATION	PLAQUEMINE	3/26/96	4/21/97	GENERATOR, NATURAL GAS FIRED TURBINE	1123 MM BTU/HR	25 PPMV CORR. TO 15%O2	CONTROL NOX USING STEAM INJECTION	BACT-PSD
LA-0093	FORMOSA PLASTICS CORPORATION, BATON ROUGE PLA	BATON ROUGE	3/7/97	4/28/97	TURBINE/HSRG, GAS COGENERATION	450 MM BTU/HR	9 PPMV	DLN DESIGN AND CONSTRUCTION.	BACT-PSD
LA-0096	UNION CARBIDE CORPORATION	HAHNVILLE	9/22/95	5/31/97	GENERATOR, GAS TURBINE	1313 MM BTU/HR	25 PPMV CORR. TO 15% O2	DRY LOW NOX COMBUSTOR	BACT-PSD
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	TURBINE, 38 MW NATURAL FAS FIRED	412 MMBTU/HR	25 PPM @ 15% O2	WATER INJECTION	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	0.7 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	TURBINE, COMBUSTION, ABB GT11N2	1327 MMBTU/H	17.12 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	TURBINE, NATURAL GAS FIRED ELECTRIC	90 MW	199 LB/HR	WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	33049	7/20/94	TURBINE, 105 MW NATURAL GAS FIRED ELECTRIC	105 MW	77 PPM @ 15% O2	DRY PREMIX AND 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 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 MW	77 PPM @ 15% O2	DRY PREMIX AND 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 MW	25 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 MW	15 PPM @ 15% O2	DRY BURN LOW NOX BURNERS	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	TURBINE, 140 MW NATURAL GAS FIRED ELECTRIC	140 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 MW	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	TURBINE, 124 MW NATURAL GAS FIRED	125 MW	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
ME-0018	WESTBROOK POWER LLC	WESTBROOK	12/4/98	4/19/99	TURBINE, COMBINED CYCLE, TWO	528 MW TOTAL	2.5 PPM @15% O2	SCR AND DRY LOW NOX BUR- NERS.	LAER
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	DLN	BACT-OTHER
ME-0020	CASCO RAY ENERGY CO	VEAZIE	7/13/98	4/19/99	TURBINE, COMBINED CYCLE, NATURAL GAS, TWO	170 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	1805.9 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 MW	4.5 PPM	SCR	BACT
MS-0030	SOUTHERN NATURAL GAS COMPANY	BAY SPRINGS	12/17/96	3/24/97	TURBINE, NATURAL GAS-FIRED	9160 HORSEPOWER	110 PPMV @ 15% O2, DRY	PROPER TURBINE DESIGN AND OPERATION	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	119 LB/HR	MAXIMUM WATER INJECTION	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	TURBINE, COMBUSTION	1313 MM BTU/HR	119 LB/HR	MAXIMUM WATER INJECTION	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	TURBINE, NATURAL GAS FIRED	585 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	1000 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 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)	1190 MMBTU/HR (EACH)	0.033 LB/MMBTU	SCR, DRY LOW NOX BURNER	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	TURBINES (NATURAL GAS) (2)	1190 MMBTU/HR (EACH)	0.033 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 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	86.6 MMBTU/H	0.34 LB/MMBTU		RACT
NJ-0031	UNIVERSITY OF MEDICINE & DENTISTRY OF NEW JERSEY	NEWARK	6/26/97	2/17/99	COMBUSTION TURBINE COGENERATION UNITS, 3	56 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	11257 HP	42 PPM @ 15% O2	SOLONOX COMBUSTOR, DLN	BACT-PSD
NM-0021	WILLIAMS FIELD SERVICES CO. - EL CEDRO COMPRESSOR	BLANCO	10/29/93	3/2/94	ENGINE, GAS-FIRED, RECIPROCATING	1000 HP	1.4 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	7.4 LBS/HR	LEAN-PREMIXED COMBUSTION TECHNOLOGY. DLN	BACT-PSD
NM-0024	MILAGRO, WILLIAMS FIELD SERVICE	BLOOMFIELD		5/29/95	TURBINE/COGEN, NATURAL GAS (2)	900 MMCF/DAY	9 PPM @ 15% O2	DLN (GENERAL ELECTRIC MODEL PG6541B)	BACT-PSD
NM-0028	SOUTHWESTERN PUBLIC SERVICE CO/CUNNINGHAM STA	HOBBS	11/4/96	12/30/96	COMBUSTION TURBINE, NATURAL GAS	100 MW	15 PPM (SEE FAC. NOTES)	DRY LOW NOX COMBUSTION	BACT-PSD
NM-0029	SOUTHWESTERN PUBLIC SERVICE COMPANY/CUNNINGHA	HOBBS	2/15/97	3/31/97	COMBUSTION TURBINE, NATURAL GAS	100 MW	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 MW	74.4 LBS/HR	DLN	BACT-PSD
NM-0039	TNP TECHN, LLC (FORMERLY TX-NM POWER CO.)	LORDSBURG	8/7/98	2/10/99	GAS TURBINES	375 MMBTU/H	15 PPM	WATER INJECTION FOLLOWED BY SCR	BACT-PSD
NV-0017	NEVADA POWER COMPANY, HARRY ALLEN PEAKING PLA	LAS VEGAS	9/18/92	3/24/95	COMBUSTION TURBINE ELECTRIC POWER GENERATION	600 MW (8 UNITS 75 E	88.6 TPY (EACH TURBINE)	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	3.5 PPM @ 15% O2	SCR	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	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)	1173 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)	1173 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)	1123 MMBTU/HR (EACH)	9 PPM	SCR	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GENERATOR, EMERGENCY (NATURAL GAS)	1.5 MMBTU/HR	1.3 LB/MMBTU	LEAN BURN ENGINE	BACT-OTHER
NY-0048	KAMINE/BESICORP CORNING L.P.	SOUTH CORNING	11/5/92	9/13/94	TURBINE, COMBUSTION (79 MW)	653 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)	2133 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 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)	5500 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	14600 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 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)	1720 MMBTU	4.5 PPM @ 15% O2	SCR	BACT-PSD
OR-0011	HERMISTON GENERATING CO.	HERMISTON	34522	1/27/99	TURBINES, NATURAL GAS (2)	1696 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 MMBTU/HR	21 LB/HR	SCR WITH LOW NOX COMBUSTORS	BACT-OTHER
PA-0130	PROCTOR AND GAMBLE PAPER PRODUCTS CO (CHARMIN	MEHOOPANY	5/31/95	11/27/95	TURBINE, NATURAL GAS	580 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 MW	4 PPM @ 15% O2	DRY LNB WITH SCR WATER INJECTION FOR OIL	LAER
PA-0149	BUCKNELL UNIVERSITY	LEWISBURG	11/26/97	11/30/97	NG FIRED TURBINE, SOLAR TAURUS T-7300S	5 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 MW	60 LB/HR	STEAM/WATER INJECTION AND SCR.	BACT-PSD
PR-0004	ECOELECTRICA, L.P.	PENUELAS	10/1/96	5/6/98	TURBINES, COMBINED-CYCLE COGENERATION	461 MW	73 LB/HR	STEAM/WATER INJECTION AND SCR.	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	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 MMBTU/H	100 PPM @ 15% O2	LOW NOX COMBUSTION	BACT-OTHER
SC-0029	SC ELECTRIC AND GAS COMPANY - HAGOOD STATION	CHARLESTON	12/11/89	3/24/95	INTERNAL COMBUSTION TURBINE	110 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
WA-0027	SUMAS ENERGY INC.	SUMAS	6/25/91	8/1/91	TURBINE, NATURAL GAS	88 MW	6 PPM @ 15% O2	SCR	BACT-PSD
WA-0274	NORTHWEST PIPELINE COMPANY	SUMAS	8/13/92	4/5/95	TURBINE, GAS-FIRED	12100 HP	196 PPM @ 15% O2	ADVANCED DLN (BY 07/01/95)	BACT-PSD
WY-0032	QUESTAR PIPELINE CORP. - RK SPRINGS COMPRESSOR C	ROCK SPRINGS	9/25/97	2/1/99	TURBINE COMPRESSOR ENGINE, NATURAL GAS FIRED, 2EA	1001 HP	2.8 G/B-HP-H		BACT-PSD
WY-0039	TWO ELK GENERATION PARTNERS, LIMITED PARTNERSHI	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 1999.

Table 5-22. RBLC NO_x Summary for Distillate/Multiple Fuel Fired CTGs

RBLC ID	Facility Name	City	Permit Dates Issuance	Permit Dates Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
AL-0069	INTERNATIONAL PAPER CO. RIVERDALE MILL	SELMA	1/11/93	3/24/95	GAS/OIL	TURBINE, STATIONARY (GAS-FIRED) WITH DUCT	40 MW	0.08 LB/MMBTU (GAS)	STEAM INJECTI ON INTO THE TURBINE	BACT-PSD
AL-0126	MOBILE ENERGY LLC	MOBILE	1/5/99	4/9/99	GAS/OIL	TURBINE, GAS, COMBINED CYCLE	168 MW	0.019 LB/MMBTU	SCR & DLN COMBUSTORS DURING GAS FIRING. ST	BACT-PSD
CA-0611	BANK OF AMERICA LOS ANGELES DATA CENTER		6/24/93	3/24/95	DIESEL	TURBINE, DIESEL & GENERATOR (SEE NOTES)		163 PPM @ 15% O2	FUEL SPEC: LOW NOX DIESEL FUEL (SEE NOTES)	BACT-OTHER
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0045	CHARLES LARSEN POWER PLANT	CITY OF OF LAKELAND	7/25/91	3/24/95	GAS/OIL	TURBINE, OIL, 1 EACH	80 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	65 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0052	FLORIDA POWER AND LIGHT	NORTH PALM BEACH	6/5/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	400 MW	65 PPM @ 15% O2	LOW NOX COMBUSTORS	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		65 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0053	FLORIDA POWER AND LIGHT	LAVOGROME REPOWERING S	3/14/91	3/24/95	GAS/OIL	TURBINE, OIL, 4 EACH		65 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0054	LAKE COGEN LIMITED	UMATILLA	11/20/91	3/24/95	GAS/OIL	TURBINE, OIL, 2 EACH	42 MW	42 PPM @ 15% O2	COMBUSTION CONTROL	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0056	ORLANDO UTILITIES COMMISSION	TITUSVILLE	11/5/91	5/14/93	GAS/OIL	TURBINE, OIL, 4 EACH	35 MW	65 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0057	FLORIDA POWER GENERATION	DEBARY	10/18/91	3/24/95	GAS/OIL	TURBINE, OIL, 6 EACH	92.9 MW	42 PPM @ 15% O2	WET INJECTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0072	TIGER BAY LP	FT. MEADE	5/17/93	1/13/95	GAS/OIL	TURBINE, OIL	1849.9 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	4/7/93	1/13/95	GAS/OIL	TURBINE, FUEL OIL	928 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0078	KISSIMMEE UTILITY AUTHORITY	INTERCESSION CITY	34066	1/13/95	GAS/OIL	TURBINE, FUEL OIL	371 MMBTU/H	42 PPM @ 15% O2	WATER INJECTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	42 PPMVD @ 15 % O2	STEAM INJECTION	BACT-PSD
FL-0080	AUBURNDALE POWER PARTNERS, LP	AUBURNDALE	12/14/92	1/13/95	GAS/OIL	TURBINE, OIL	1170 MMBTU/H	42 PPMVD @ 15 % O2	STEAM INJECTION	BACT-PSD
FL-0081	TECO POLK POWER STATION	BARTOW	2/24/94	3/24/95	GAS/OIL	TURBINE, FUEL OIL	1765 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
FL-0082	FLORIDA POWER CORPORATION POLK COUNTY SITE	BARTOW	2/25/94	1/13/95	GAS/OIL	TURBINE, FUEL OIL (2)	1730 MMBTU/H	42 PPMVD @ 15 %O2	WATER INJECTION	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1029 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0083	FLORIDA POWER CORPORATION	INTERCESSION CITY	8/17/92	1/13/95	GAS/OIL	TURBINE, OIL	1866 MMBTU/H	42 PPMVD @ 15 % O2	WET INJECTION	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	GAS/OIL	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	BACT-PSD
FL-0092	GAINESVILLE REGIONAL UTILITIES	GAINESVILLE	4/11/95	5/29/95	GAS/OIL	OIL FIRED COMBUSTION TURBINE	74 MW	42 PPM AT 15% OXYGEN	WATER INJECTION	BACT-PSD
FL-0104	SEMINOLE HARDEE UNIT 3	FORT GREEN	1/1/96	5/31/96	GAS/OIL	COMBINED CYCLE COMBUSTION TURBINE	140 MW	15 PPM @ 15% O2	DRY LNB STAGED COMBUSTION	BACT-PSD
FL-0115	CITY OF LAKELAND ELECTRIC AND WATER UTILITIES	LAKELAND	7/10/98	4/16/99	GAS/OIL	TURBINE, COMBUSTION, GAS FIRED W/ FUEL OIL	2174 MMBTU/H	25 PPM @ 15% O2	DLN FOR SIMPLE CYCLE, SCR WHEN COMBINED CY	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	SEE NOTES	MAX WATER INJECTION	BACT-PSD
GA-0052	SAVANNAH ELECTRIC AND POWER CO.		2/12/92	3/24/95	GAS/OIL	TURBINES, 8	972 MMBTU/H, #2 OIL	SEE NOTES	MAX WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	BACT-PSD
GA-0053	HARTWELL ENERGY LIMITED PARTNERSHIP	HARTWELL	7/28/92	3/24/95	GAS/OIL	TURBINE, OIL FIRED (2 EACH)	1840 M BTU/HR	25 PPMVD, FUEL N AFLOW	MAXIMUM WATER INJECTION	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	BACT-PSD
GA-0063	MID-GEORGIA COGEN.	KATHLEEN	4/3/96	8/19/96	GAS/OIL	COMBUSTION TURBINE (2), FUEL OIL	116 MW	20 PPMVD	WATER INJECTION WITH SCR	BACT-PSD
HI-0013	MAUI ELECTRIC COMPANY, LTD.	MAALAEA	12/3/91	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	28 MW	42 PPM	WATER INJECTION	BACT-PSD
HI-0014	HAWAII ELECTRIC LIGHT CO., INC.	KEEAU	2/12/92	3/24/95	GAS/OIL	TURBINE, FUEL OIL #2	20 MW	42.3 LB/HR	COMBUSTOR WATER INJECTOR, WATER INJECTIO	BACT-PSD
HI-0015	MAUI ELECTRIC COMPANY, LTD./MAALAEA GENERATING	MAUI	7/28/92	3/24/95	GAS/OIL	TURBINE, COMBINED-CYCLE COMBUSTION	28 MW	42.3 LB/HR	WATER INJECTION	BACT-OTHER
KY-0053	KENTUCKY UTILITIES COMPANY	MERCER	3/10/92	3/24/95	GAS/OIL	TURBINE, #2 FUEL OIL/NATURAL GAS (8)	1500 MM BTU/HR (EACH	42 PPM @ 15% O2, N. GAS	WATER INJECTION	BACT-PSD
KY-0057	EAST KENTUCKY POWER COOPERATIVE		34052	3/24/95	GAS/OIL	TURBINES (5), #2 FUEL OIL AND NAT. GAS FIRED	1492 MMBTU/H (EACH)	42 PPM @ 15% O2 (OIL)	WATER INJECTION	SEE NOTES
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	DIESEL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	40 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0015	PEABODY MUNICIPAL LIGHT PLANT	PEABODY	11/30/89	3/24/95	DIESEL	TURBINE, 38 MW OIL FIRED	412 MMBTU/HR	40 PPM @ 15% O2	WATER INJECTION	BACT-OTHER
MA-0021	MILLENNIUM POWER PARTNER, LP	CHARLTON	2/2/98	4/19/99	GAS/OIL	TURBINE, COMBUSTION, WESTINGHOUSE MODEL	2534 MMBTU/H	0.013 LB/MMBTU	DLN IN CONJUNCTION WITH SCR ADD-ON NOX CO	BACT-PSD
MA-0022	BERKSHIRE POWER DEVELOPMENT, INC.	AGAWAM	9/22/97	4/19/99	GAS/OIL	TURBINE, COMBUSTION, ABB GT24	1792 MMBTU/H	20.3 LB/H	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MA-0023	DIGHTON POWER ASSOCIATE, LP	DIGHTON	10/6/97	4/19/99	DIESEL	ENGINE, DIESEL, FIRE PUMP	1.5 MMBTU/H	4.41 LB/MMBTU	DLN WITH SCR ADD-ON NOX CONTROL.	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	32782	3/24/95	DIESEL	TURBINE, OIL FIRED ELECTRIC	90 MW	400 LB/HR	WATER INJECTION	BACT-PSD
MD-0017	SOUTHERN MARYLAND ELECTRIC COOPERATIVE (SMECO)	EAGLE HARBOR	10/1/89	3/24/95	DIESEL	TURBINE, OIL FIRED ELECTRIC	90 MW	400 LB/HR	WATER INJECTION	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	25 PPM @ 15% O2	DRY PREMIX BURNER	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 84 MW OIL FIRED ELECTRIC	84 MW	58 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-001B	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 105 MW OIL FIRED ELECTRIC	105 MW	25 PPM @ 15% O2	DRY PREMIX BURNER	BACT-PSD
MD-0018	PEPCO - CHALK POINT PLANT	EAGLE HARBOR	6/25/90	7/20/94	DIESEL	TURBINE, 84 MW OIL FIRED ELECTRIC	84 MW	58 PPM @ 15% O2	QUIET COMBUSTION AND WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	DIESEL	TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	65 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0019	BALTIMORE GAS & ELECTRIC - PERRYMAN PLANT	PERRYMMAN		3/24/95	DIESEL	TURBINE, 140 MW OIL FIRED ELECTRIC	140 MW	65 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	DIESEL	TURBINE, 124 MW OIL FIRED	125 MW	77 PPM @ 15% O2	WATER INJECTION	BACT-PSD
MD-0021	PEPCO - STATION A	DICKERSON	5/31/90	7/20/94	DIESEL	TURBINE, 124 MW OIL FIRED	125 MW	77 PPM @ 15% O2	WATER INJECTION	BACT-PSD
ME-0016	GORHAM ENERGY LIMITED PARTNERSHIP	GORHAM	12/4/98	4/19/99	GAS/OIL	TURBINE, COMBINED CYCLE	900 MW TOTAL	2.5 PPM @ 15% O2 (NAT G)	SCR. EMISSION IS FROM EACH 300 MW SYSTEM.	LAER
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	DIESEL	DIESEL ENGINE-DRIVEN FIRE PUMP	2.7 MMBTU/HR	5 LB/HR	RETARDATION OF ENGINE TIMING, TURBOCHARGE	BACT-PSD
MN-0022	LSP-COTTAGE GROVE, L.P.	COTTAGE GROVE	3/1/95	5/29/95	GAS/OIL	COMBUSTION TURBINE/GENERATOR	1970 MMBTU/HR	4.5 PPM @ 15% O2 GAS	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	DIESEL	ENGINE, DIESEL, EMERGENCY FIRE PUMP	2.7 MMBTU/H	1.85 LB/MMBTU	LIMITED TO BURN DIESEL 150 H/YR.	BACT-PSD
MN-0035	LSP - COTTAGE GROVE, L.P.	COTTAGE GROVE	11/10/98	4/19/99	GAS/OIL	GENERATOR, COMBUSTION TURBINE & DUCT BU	1988 MMBTU/H (CTG)	4.5 PPMDV @15%O2 (NG)	SCR WITH A NOX CEM AND A NOX PEM.	BACT-PSD
MO-0013	HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	7/27/95	10/6/97	GAS/OIL	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49.1 MW	75 PPM BY VOL 1 HR AVG	CONTROLS FOR FUEL CONSUMPTION AND WATER	BACT-PSD
MO-0013	HIGGINSVILLE MUNICIPAL POWER FACILITY	HIGGENSVILLE	7/27/95	10/6/97	GAS/OIL	ADD OF A DUAL FUEL FIRED TWIN-PAC TURBINE	49.1 MW	42 PPM BY VOL 1 HR AVG	CONTROLS FOR FUEL CONSUMPTION AND WATER	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	1135 TPY	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
MO-0016	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	5/17/94	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	1345 MMBTU\HR	25 PPM BY VOL 1 HR AVG	LOW NOX BURNERS, AND WATER INJECTION	BACT-PSD
MO-0017	EMPIRE DISTRICT ELECTRIC CO.	JOPLIN	2/28/95	10/6/97	GAS/OIL	INSTALL TWO NEW SIMPLE-CYCLE TURBINES	88.77 MW	360 TPY	WATER INJECTION.	BACT-PSD
MO-0043	UNION ELECTRIC CO	WEST ALTON	5/6/79	10/6/97	GAS/OIL	CONSTRUCTION OF A NEW OIL FIRED COMBUSTI	622 MM BTU/HR	5242 TPY	WATER INJECTION FOR NOX EMISSIONS	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	12/20/91	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER IN	BACT-PSD
NC-0055	DUKE POWER CO. LINCOLN COMBUSTION TURBINE STATI	LOWESVILLE	33592	3/24/95	GAS/OIL	TURBINE, COMBUSTION	1247 MM BTU/HR	287 LB/HR	MULTINOZZLE COMBUSTOR, MAXIMUM WATER IN	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	158 LB/HR	WATER INJECTION	BACT-PSD
NC-0059	CAROLINA POWER & LIGHT	GOLDSBORO	4/11/96	8/19/96	GAS/OIL	COMBUSTION TURBINE, 4 EACH	1907.6 MMBTU/HR	512.3 LB/HR	WATER INJECTION, FUEL SPEC: 0.04% N FUEL OIL	BACT-PSD
NJ-0009	NEWARK BAY COGENERATION PARTNERSHIP	NEWARK	11/1/90	7/7/93	GAS/OIL	TURBINE, KEROSENE FIRED	585 MMBTU/HR	0.063 LB/MMBTU	STEAM INJECTION AND SCR	BACT-PSD
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.082 LB/MMBTU	SCR AND WATER INJECTION	BACT-OTHER
NJ-0013	LAKEWOOD COGENERATION, L.P.	LAKEWOOD TOWNSHIP	4/1/91	5/29/95	GAS/OIL	TURBINES (#2 FUEL OIL) (2)	1190 MMBTU/HR (EACH)	0.082 LB/MMBTU	SCR AND WATER INJECTION	BACT-OTHER

Table 5-22. RBLC NO_x Summary for Distillate/Multiple Fuel Fired CTGs (Page 2 of 2)

RBLC ID	Facility Name	City	Permit Dates Issuance	Update	Fuel Type	Process Description	Thruput Rate	Emission Limit	Control System Description	Basis
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MW EACH	NOT APPLICABLE	GOOD COMBUSTION PRACTICE	RACT
NJ-0029	ALGONQUIN GAS TRANSMISSION COMPANY	HANOVER	3/31/95	2/10/99	GAS/OIL	TURBINES COMBUSTION, TWO SOLAR CENTAUR	3.1 MW EACH	43.38 LB/H		BACT
NV-0015	SAGUARO POWER COMPANY	HENDERSON	6/17/91	6/1/93	GAS/OIL	COMBUSTION TURBINE GENERATOR	34.5 MW	16.9 PPH (WINTER)	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
NV-0030	MUDDY RIVER L.P.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	303 LB/HR	LOW NOX BURNER	BACT-PSD
NV-0031	CSW NEVADA, INC.	MOAPA	6/10/94	3/24/95	GAS/OIL	COMBUSTION TURBINE, DIESEL & NATURAL GAS	140 MEGAWATT	273 LB/HR	DRY LOW NOX COMBUSTOR	BACT-PSD
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	10 PPM @ 15% O2	SCR	LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	2.6 LB/MMBTU		LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	TURBINE, OIL FIRED	240 MW	10 PPM @ 15% O2	SCR	LAER
NY-0044	BROOKLYN NAVY YARD COGENERATION PARTNERS L.P.	NEW YORK CITY	6/6/95	6/30/95	DIESEL	GENERATOR, 3000 KW EMERGENCY	3000 KW	2.6 LB/MMBTU		LAER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	DIESEL	FIRE PUMP (DIESEL)	1.3 MMBTU/HR	1.3 LB/MMBTU	LEAN BURN ENGINE	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	9 PPM	DRY LOW NOX	BACT-OTHER
NY-0047	PASNY/HOLTSVILLE COMBINED CYCLE PLANT	HOLTSVILLE	9/1/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION GAS (150 MW)	1146 MMBTU/HR (GAS)*	42 PPM	WATER INJECTOR	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILI	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (	650 MMBTU/HR	9 PPM	DRY LOW NOX OR SCR	BACT-OTHER
NY-0049	KAMINE/BESICORP BEAVER FALLS COGENERATION FACILI	BEAVER FALLS	11/9/92	9/13/94	GAS/OIL	TURBINE, COMBUSTION (NAT. GAS & OIL FUEL) (	650 MMBTU/HR	55 PPM	DRY LOW NOX OR SCR	BACT-OTHER
NY-0057	MEGAN-RACINE ASSOCIATES, INC	CANTON	8/5/89	3/30/95	GAS/OIL	GE LM5000-N COMBINED CYCLE GAS TURBINE	401 LB/MMBTU	42 PPMDV @ 15% O2	WATER INJECTION	BACT
NY-0061	ANITEC COGEN PLANT	BINGHAMTON	7/7/93	4/27/95	GAS/OIL	GE LM5000 COMBINED CYCLE GAS TURBINE EP #	451 MMBTU/HR	25 PPM, 41 LB/HR	NO CONTROLS	BACT-OTHER
NY-0062	FULTON COGEN PLANT	FULTON	34592	4/27/95	GAS/OIL	GE LM5000 GAS TURBINE	500 MMBTU/HR	36 PPM, 65 LB/HR	WATER INJECTION	BACT
NY-0063	TBG COGEN COGENERATION PLANT	BETHPAGE	8/5/90	4/27/95	GAS/OIL	GE LM2500 GAS TURBINE	214.9 MMBTU/HR	75 PPM + FBN CORRECTION	WATER INJECTION	BACT
NY-0064	INDECK-OSWEGO ENERGY CENTER	OSWEGO	10/6/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	533 LB/MMBTU	42 PPM, 75.00 LB/HR	STEAM INJECTION	BACT
NY-0065	KAMINE/BESICORP CARTHAGE L.P.	CARTHAGE	1/18/94	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	491 BTU/HR	42 PPM, 76.6 LB/HR	STEAM INJECTION	BACT
NY-0066	INDECK ENERGY COMPANY	SILVER SPRINGS	5/12/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE EP #00001	491 MMBTU/HR	32 PPM	STEAM INJECTION	BACT
NY-0068	KAMINE/BESICORP NATURAL DAM LP	NATURAL DAM	12/31/91	6/30/95	GAS/OIL	GE FRAME 6 GAS TURBINE	500 MMBTU/HR	42 PPM, 80.1 LB/HR	STEAM INJECTION	BACT
NY-0071	KAMINE SOUTH GLENS FALLS COGEN CO	SOUTH GLENS FALLS	9/10/92	4/27/95	GAS/OIL	GE FRAME 6 GAS TURBINE	498 MMBTU/HR	42 PPM, 76.6 LB/HR	WATER INJECTION	BACT
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	DIESEL GENERATOR (EP #00005)	22 MMBTU/HR	1.166 LB/MMBTU, 26.0 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	DIESEL	FIRE PUMP (EP #00007)	1.5 MMBTU/HR	4.25 LB/MMBTU, 6.25 LB/HR	NO CONTROLS	BACT-OTHER
NY-0072	KAMINE/BESICORP SYRACUSE LP	SOLVAY	12/10/94	4/27/95	GAS/OIL	SIEMENS V64.3 GAS TURBINE (EP #00001)	650 MMBTU/HR	25 PPM	WATER INJECTION	BACT
NY-0073	LOCKPORT COGEN FACILITY	LOCKPORT	7/14/93	4/27/95	GAS/OIL	(6) GE FRAME 6 TURBINES (EP #S 00001-00006)	423.9 MMBTU/HR	42 PPM	STEAM INJECTION	BACT
NY-0075	PILGRIM ENERGY CENTER	ISLIP		4/27/95	GAS/OIL	(2) WESTINGHOUSE W501D5 TURBINES (EP #S 0	1400 MMBTU/HR	4.5 PPM, 23.6 LB/HR	STEAM INJECTION FOLLOWED BY SCR	BACT
NY-0076	TRIGEN MITCHEL FIELD	HEMPSTEAD	4/16/93	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE	424.7 MMBTU/HR	60 PPM, 90 LB/HR	STEAM INJECTION	BACT
NY-0077	INDECK-YERKES ENERGY SERVICES	TONAWANDA	6/24/92	3/31/95	GAS/OIL	GE FRAME 6 GAS TURBINE (EP #00001)	432.2 MMBTU/HR	42 PPM, 74 LB/HR	STEAM INJECTION	BACT
NY-0079	LEDERLE LABORATORIES	PEARL RIVER		4/27/95	GAS/OIL	(2) GAS TURBINES (EP #S 00101&102)	110 MMBTU/HR	42 PPM, 18 LB/HR	STEAM INJECTION	BACT-PSD
NY-0081	LILCO SHOREHAM	HICKSVILLE	5/10/93	3/30/95	DIESEL	(3) GE FRAME 7 TURBINES (EP #S 00007-9)	850 MMBTU/HR	55 PPM + FBN & HEAT RATE	WATER INJECTION	BACT
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58 MW	25 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-OTHER
OK-0027	OKLAHOMA MUNICIPAL POWER AUTHORITY	PONCA CITY	12/17/92	3/24/95	GAS/OIL	TURBINE, COMBUSTION	58 MW	65 PPM @ 15% O2	COMBUSTION CONTROLS	BACT-OTHER
PA-0083	NORTHERN CONSOLIDATED POWER	NORTH EAST	5/3/91	7/20/94	DIESEL	GENERATORS, DIESEL, 2	1135 KW EACH	36 LB/H EACH		OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	TURBINE (NATURAL GAS & OIL)	1150 MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PA-0098	GRAYS FERRY CO. GENERATION PARTNERSHIP	PHILADELPHIA	11/4/92	7/20/94	GAS/OIL	GENERATOR, STEAM	450 MMBTU	9 PPMVD (NAT. GAS)*	DRY LOW NOX BURNER, COMBUSTION CONTROL	BACT-OTHER
PR-0002	PUERTO RICO ELECTRIC POWER AUTHORITY (PREPA)	ARECIBO	7/31/95	5/6/98	GAS/OIL	COMBUSTION TURBINES (3), 83 MW SIMPLE-CYC	248 MW	35 LB/HR AS NO2	STEAM INJECTION PLUS SCR. N2 NOT TO EXCEED	BACT-PSD
SC-0021	CAROLINA POWER AND LIGHT CO.	DARLINGTON	9/23/91	3/24/95	GAS/OIL	TURBINE, I.C.	80 MW	292 LB/H	WATER INJECTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	25 PPMDV @ 15% O2	WATER INJECTION	BACT-PSD
SC-0036	CAROLINA POWER AND LIGHT	HARTSVILLE	8/31/94	4/29/96	GAS/OIL	STATIONARY GAS TURBINE	1520 MMBTU/H	62 PPMDV @ 15% O2	WATER INJECTION	BACT-PSD
SC-0038	GENERAL ELECTRIC GAS TURBINES	GREENVILLE	4/19/96	8/19/96	GAS/OIL	I.C. TURBINE	2700 MMBTU/HR	885.3 LB/HR	GOOD COMBUSTION PRACTICES TO MINIMIZE EMI	BACT-PSD
SD-0001	NORTHERN STATES POWER COMPANY	NEAR SIOUX FALLS, SOUTH	9/2/92	3/24/95	GAS/OIL	TURBINE, SIMPLE CYCLE, 4 EACH	129 MW	24 PPM @ 15% O2 GAS	WATER INJECTION FOR GAS & DISTILLATION	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	1331.13 X10(7) SCF/Y NAT	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR) W/ WAT	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINE FACILITY, GAS	7.44 X10(7) GPY FUEL O	245 TOTAL TPY	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) [EACH WITH A SF]	1.51 X10(9) BTU/HR N.G	9 PPMDV/UNIT @ 15% O2	SCR WITH WATER INJECTION	BACT-PSD
VA-0189	GORDONSVILLE ENERGY L.P.	FAIRFAX	9/25/92	3/24/95	GAS/OIL	TURBINES (2) [EACH WITH A SF]	1.36 X10(9) BTU/H #2 O	66 LBS/HR/UNIT	WATER INJECTION AND SCR	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	474 X10(6) BTU/HR N.	9 PPM	SELECTIVE CATALYTIC REDUCTION (SCR)	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS	468 X10(6) BTU/HR #2	15 PPM	SCR	BACT-PSD
VA-0190	BEAR ISLAND PAPER COMPANY, L.P.	ASHLAND	10/30/92	5/7/97	GAS/OIL	TURBINE, COMBUSTION GAS (TOTAL)		69.7 TPY	SCR	BACT-PSD
VA-0206	PATOWMACK POWER PARTNERS, LIMITED PARTNERSHIP	LEESBURG	9/15/93	5/7/97	GAS/OIL	TURBINE, COMBUSTION, SIEMENS MODEL V84.2,	10.2 X109 SCF/YR NAT	131 LB/HR(GAS), 339 OIL	DRY LOW NOX COMBUSTOR, DESIGN, WATER INJE	BACT-PSD
WA-0280	EEX POWER SYSTEMS, ENCOGEN NW COGENERATION PR	BELLINGHAM	9/26/91	4/16/99	GAS/OIL	TURBINES, COMBINED CYCLE COGEN, GE FRAME	123 MW	7 PPMDV@15%O2 NG	STEAM INJECTION AND SCR	BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	33845	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		25 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD
WI-0067	WEPCU, PARIS SITE	PARIS	8/29/92	7/20/94	GAS/OIL	TURBINES, COMBUSTION (4)		65 PPM @ 15% O2	GOOD COMBUSTION PRACTICES	BACT-PSD

Source: RBLC 1999.

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

Permit Date	Source Name	Turbine Size (MW)	NO_x Emission Limit (ppmvd)	Control Technology
08/17/92	Orlando Cogeneration, L.P.	79	15	DLN combustors
08/17/92	Florida Power Corp. University of Florida	43	25	Steam injection
12/17/92	Auburndale Power Partners	104	25	Steam injection
			15	Steam injection
04/09/93	Kissimmee Utility Authority	40	25	Water injection
			15	DLN combustors
04/09/93	Kissimmee Utility Authority	80	25	Water injection
			15	DLN combustors
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	25	DLN combustors
		184	15	DLN combustors
02/21/94	Polk Power Partners	84	25	DLN combustors
			15	DLN combustors
02/24/94	Tampa Electric Company Polk Power Station	260	25	Nitrogen diluent injection
07/20/94	Pasco Cogen, Limited	42	25	Wet injection
03/07/95	Orange Cogeneration, L.P.	39	15	DLN combustors
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	15	DLN combustors
06/01/95	Panda-Kathleen	75	15	DLN combustors
09/28/95	City of Key West (relocated unit)	23	75	Water injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	15	DLN combustors
05/98	City of Tallahassee Purdom Unit 8	160	12	DLN combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	25	DLN combustors
07/10/98	City of Lakeland McIntosh Unit 5	250	9	DLN combustors or SCR (effective 05/01/2002)
09/28/98	Florida Power Corp. Hines Energy Complex	165	12	DLN combustors and/or SCR
12/04/98	Santa Rosa Energy Center	167	9	DLN combustors

Source: FDEP, 1998.

Table 5-24. Florida BACT NO_x Summary—Distillate Fuel Oil-Fired CTGs

Permit Date	Source Name	Turbine Size (MW)	NO_x Emission Limit (ppmvd)	Control Technology
08/17/92	Florida Power Corp. University of Florida	43	42	Steam injection
08/17/92	Florida Power Corp. Intercession City	93	42	Wet injection
08/17/92	Florida Power Corp. Intercession City	186	42	Steam injection
12/17/92	Auburndale Power Partners	104	42	Steam injection
04/09/93	Kissimmee Utility Authority	40	42	Water injection
04/09/93	Kissimmee Utility Authority	80	42	Water injection
05/17/93	Central Florida Power, L.P. (Tiger Bay - Destec)	184	42	Wet injection
02/21/94	Polk Power Partners	84	42	Wet injection
02/24/94	Tampa Electric Company Polk Power Station	260	42	Wet injection
07/20/94	Pasco Cogen, Limited	42	42	Wet injection
04/11/95	Gainesville Regional Utilities Deerhaven CT3	74	42	Wet injection
01/01/96	Seminole Electric Cooperative, Inc., Hardee Unit 3	140	—	—
05/98	City of Tallahassee Purdom Unit 8	160	42	Water or steam injection
07/10/98	City of Lakeland McIntosh Unit 5	250	42	Water injection
09/28/98	Florida Power Corp. Hines Energy Complex	165	42	Water injection

Source: FDEP, 1998.

Table 5-25. Proposed NO_x BACT Emission Limits

Emission Source	Proposed NO_x BACT Emission Limits lb/hr*	ppmvd†
GE PG 7121 (7EA) CTG (Natural Gas firing)	32	9
GE PG 7121 (7EA) CTG (Distillate Fuel Oil firing)	166	42

*At ISO conditions.
†Corrected to 15-percent oxygen.

Sources: GE, 1999.
ECT, 1999.

Table 5-26. Summary of BACT Control Technologies

Pollutant	Control Technology
GE PG7121 (7EA) CTG, CC-1	
PM_{10}	• Exclusive use of low-ash and low-sulfur natural gas and distillate fuel oil. • Efficient combustion.
CO	• Efficient combustion.
NO_x	• Use of advanced dry low-NO_x burners (natural gas firing). • Use of wet injection (distillate fuel oil firing).

Source: ECT, 1999.

Table 5-27. Summary of Proposed BACT Emission Limits

Emission Source	Pollutant	Proposed BACT Emission Limits ppmvd	lb/hr
GE PG7121 (7EA) CTG (Natural Gas firing)			
	PM_{10}	10-percent opacity	
	CO*	25	54†
	CO	20	43†
	NO_x	9**‡	32†
GE PG7121 (7EA) CTG (Distillate Fuel Firing)			
	PM_{10}	10-percent opacity	
	CO	20	43†
	NO_x	42**‡	166†

*First year operation.
†At ISO conditions.
**Corrected to 15-percent oxygen.
‡24-hour block average.

Sources: GE, 1999.
ECT, 1999.

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 practice. Guidance contained in EPA manuals and user's guides was sought and followed.

6.2 POLLUTANTS EVALUATED

Based on an evaluation of anticipated worst-case annual operating scenarios, the repowering project will have net potential emission increases of 113 tpy NO_x, 171 tpy of CO, 23 tpy of PM/PM_{10}, 18 tpy of SO_2, 7 tpy of VOCs, and 5 tpy of H_2SO_4 mist. Table 3-2 previously provided a comparison of estimated potential annual emission rates for the repowering project and the PSD significant emission rate thresholds. As shown in that table, potential emissions of NO_x, CO, and PM_{10} 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 repowering project CTG. 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 99551, was used with a range of predefined, worst-case meteorological conditions. The worst-case meteorological conditions (54 combinations of wind speed 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 wind speed 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 wind speed/stability class combinations times 36 wind directions).

Use of the ISCST3 model with the screening meteorology described above is considered to provide a better analysis of worst-case CTG operating scenarios (i.e., to determine which CTG 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 repowering project CTG may operate under a variety of operating scenarios. These scenarios include different loads, ambient air temperatures, and fuel type (i.e., natural gas or distillate fuel oil), and different modes of operation (i.e., simple- or combined-cycle modes). 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 five years of actual, historical meteorological data (i.e., refined mode ISCST3 modeling). A nominal emission rate of 1.0 grams 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 version of the ISC3 models (EPA, 1998) is recommended and was 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 ISC3 short-term (ISCST3) (Version 99551) 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. In general, urban areas cause greater rates of dispersion because of increased turbulent mixing and buoyancy-induced mixing. This is due to the combination of greater surface roughness caused by more buildings and structures and greater amount of heat released from concrete and similar surfaces. 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.

USGS 7.5-minute series topographic maps for the area were used to identify the land use types within a 3-km radius area of the proposed site. The area within a 3-km radius of the J.R. Kelly Generating Station is predominately single family residential dwellings with undeveloped land (i.e., the Paynes Prairie area) beginning approximately 2.0 km to the south of the plant. Based on this land use, the area within a 3-km radius would be characterized as rural using the Auer classification method. Therefore, rural dispersion coefficients and mixing heights were used for the ambient impact analysis.

6.5 TERRAIN CONSIDERATION

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

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

6.6 GOOD ENGINEERING PRACTICE STACK HEIGHT/BUILDING WAKE EFFECTS

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

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

where: Hg = GEP stack height.
H = height of the structure or nearby structure.
L = lesser dimension (height or projected width) of the nearby structure.

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

The stack heights proposed for the repowering project CTG in simple- and combined cycle modes (78 and 100 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. 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.

Table 6-1. Building/Structure Dimensions

Building/Structure	Dimensions Width (meters)	Length (meters)	Height (meters)
Building Units 7 and 8	37.2	63.1	18.6
Building Units 7 and 8 Penthouse	13.7	21.3	35.1
Building Units 4, 5, and 6	45.7	71.2	19.1
CC-1 HRSG	7.1	22.8	18.9

Sources: GRU, 1999.
ECT, 1999.

6.7 RECEPTOR GRIDS

Receptors were placed at locations considered to be *ambient air*, which is defined as "that portion of the atmosphere, external to buildings, to which the general public has access." Section 2.0 provided a plot plan showing the site fence lines (see Figure 2-2). As shown in Figure 2-2, the entire perimeter of the plant site is fenced. Therefore, the nearest locations of general public access are at the facility fence lines.

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

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

To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. Figure 6-1 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 6-2.

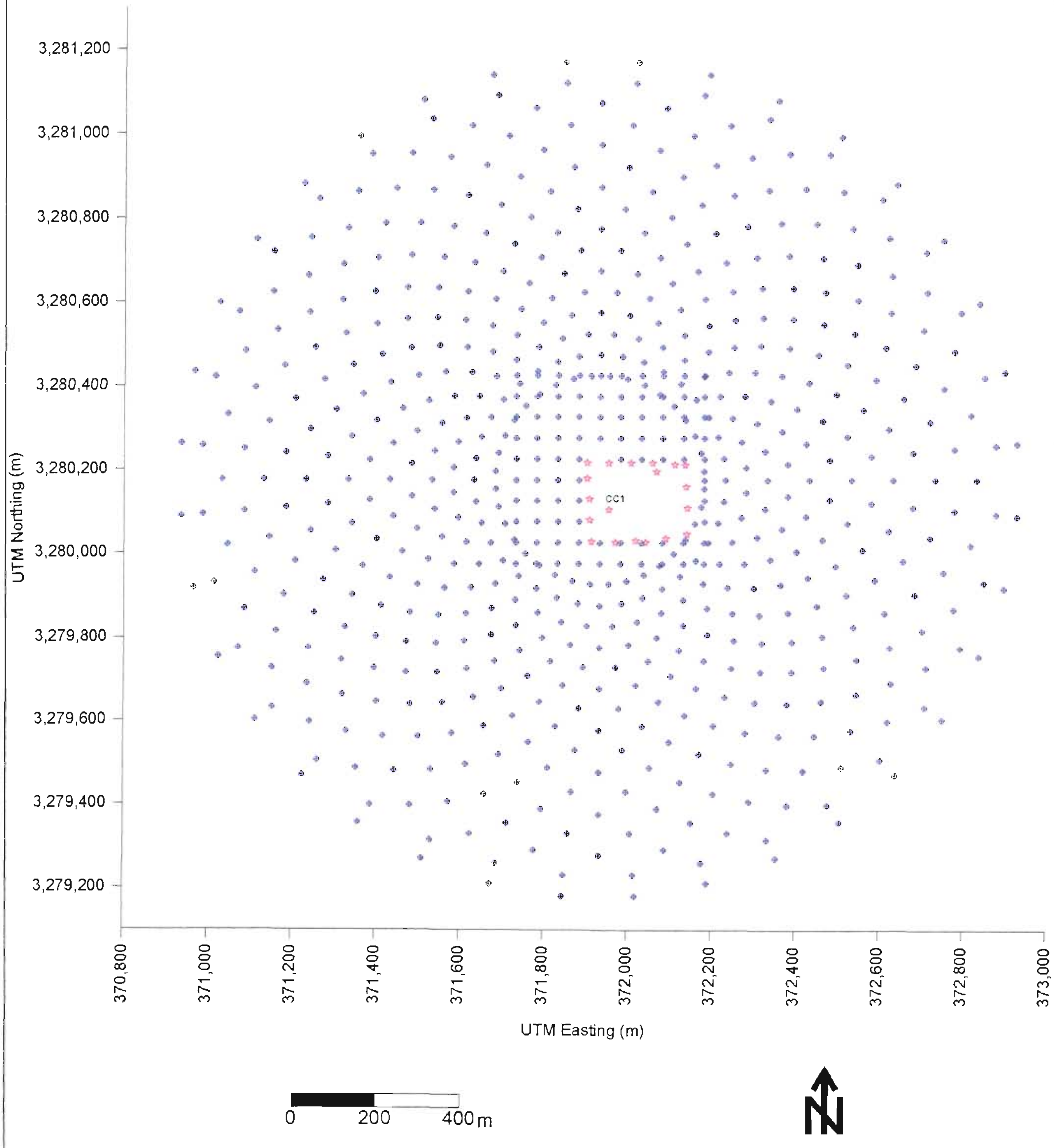


FIGURE 6-1.

RECEPTOR LOCATIONS (WITHIN 1 KM)

Source: ECT, 1999.

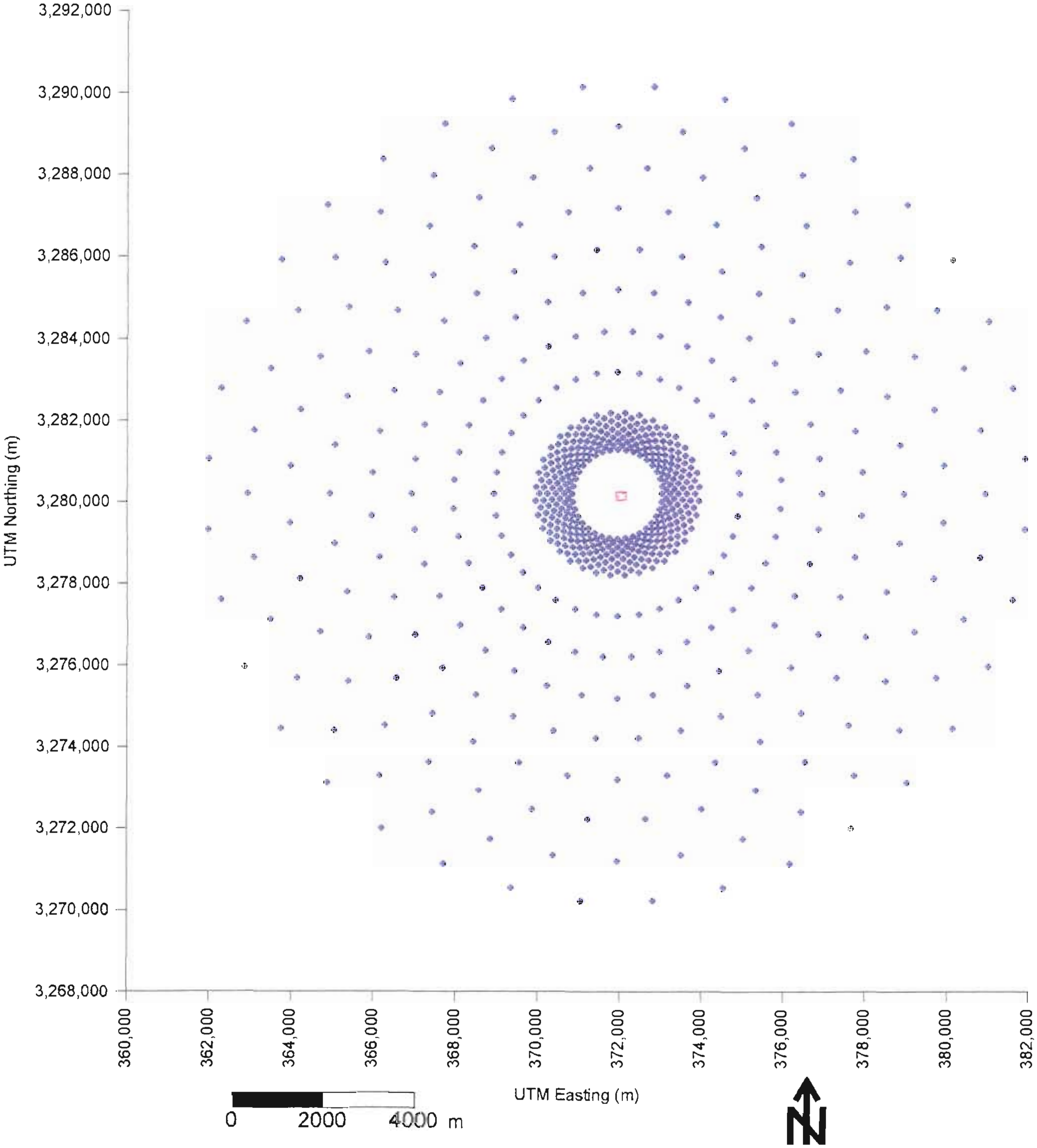


FIGURE 6-2.

RECEPTOR LOCATIONS (FROM 1 TO 10 KM)

Source: ECT, 1999.

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 Alachua County, FDEP recommends use of Gainesville, Florida surface and Waycross, Georgia upper air meteorological data in conducting the air quality analyses. As recommended by FDEP, 1984 through 1988 Gainesville surface (Gainesville Regional Airport—Station No. 12816) and Waycross upper air (Waycross—Station No. 13861) meteorological data were used in the Ambient Impact Analysis.

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

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 Gainesville and Waycross 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, Gainesville surface station latitude and longitude coordinates (in decimal degrees) are 29.683 and 82.267, respectively. The Gainesville surface station is located in time zone 5.

Actual anemometer height for the Gainesville surface station, obtained from the National Climatic Data Center (NCDC), is 22 ft (6.7 meters) for the time period of interest (i.e., 1984 through 1988).

Processing of the Gainesville and Waycross station meteorological data did not require any data replacement or substitution.

6.9 MODELED EMISSION INVENTORY

The modeled on-property emission source consisted of the new, proposed CTG (CC-1). Conservatively, no credit was taken for the emission reductions associated with the cessation of operations of Unit 8. As will be discussed in Section 7.0, Ambient Impact Analysis Results, emissions from the new CTG resulted in air quality impacts below the significance impact levels (reference Table 4-2) for all pollutants and all averaging periods. Accordingly, additional, multisource interactive dispersion modeling was not required.

Emission rates and stack parameters for the new CTG (CC-1) were previously presented in Tables 2-1 through 2-11.

7.0 AMBIENT IMPACT ANALYSIS RESULTS

7.1 SCREENING ANALYSIS

The ISCST3 dispersion model, screening mode, was used to assess each of the 18 CTG operating cases (i.e., a matrix of three CTG loads [100-, 80-, and 60-percent]; three ambient temperatures [20, 59, and 95°F]; and two operating modes [simple-cycle and combined-cycle]) for each pollutant subject to PSD review [NO_2, PM_{10}, and CO]). The screening analysis was confined to the fuel oil-firing CTG operational scenarios because emission rates are higher than gas-firing for all pollutants. The worst-case operating modes identified by the ISCST3 screening mode model for each pollutant were then carried forward to the refined modeling for further analysis.

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

Tables 7-1 and 7-2 provide ISCST3 model (screening mode) maximum NO_2 and PM_{10} 1-hour impacts for the repowering project long-term (i.e., annual averaging period) operating scenarios. The model results shown in Tables 7-1 and 7-2 reflect annualized emission rates and an annual average temperature of 59°F. Tables 7-3 and 7-4 provide ISCST3 model (screening mode) maximum CO and PM_{10} 1-hour impacts for the repowering project short-term (i.e., 1-, 8-, and 24-hour averaging periods) operating scenarios. Tables 7-1 through 7-4 indicate, for each operating case, the maximum emission rates for the CTG, ISCST3 screening mode model results based on a nominal 1.0-g/s emission rate, emission rate scaling factor, scaled ISCST3 screening mode model result, and location of maximum impact.

As shown in the ISCST3 model (screening mode) summary tables, for both simple-cycle and combined-cycle long-term (i.e., annual averaging period) operating scenarios, maximum 1-hour impacts for NO_2 and PM_{10} occurred under Case 6 operating conditions (i.e., 60-percent load and 59°F ambient temperature). For both simple-cycle and combined-

Table 7-1. ISCST3 (Screening Mode) Model Results—NO_2 Impacts (Long-Term Operating Scenarios)

Operating Scenarios					1-Hour Impacts ($\mu g/m^3$)		
Case Number	Load (%)	Ambient Temperature (°F)	Annualized Emission Rate (g/s)	Operating Mode	ISCST3 Unadjusted Results*	Emission Rate Factor†	ISCST3 Adjusted Results**
SC-4	100	59	5.961	Simple-Cycle	4.45	5.961	26.53
SC-5	80	59	5.961	Simple-Cycle	7.94	5.961	47.33
SC-6	**60**	**59**	**5.961**	**Simple-Cycle**	**10.62**	**5.961**	**63.31**
					Maximum		**63.31**
CC-4	100	59	5.961	Combined-Cycle	10.79	5.961	64.32
CC-5	80	59	5.961	Combined-Cycle	13.75	5.961	81.96
CC-6	**60**	**59**	**5.961**	**Combined-Cycle**	**16.95**	**5.961**	**101.04**
					Maximum		**101.04**

*Based on 1.0-g/s emission rate.
†Annualized emission rate (in g/s) divided by 1.0 g/s.
**ISCST3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-2. ISCST3 (Screening Mode) Model Results—PM_{10} Impacts (Long-Term Operating Scenarios)

Operating Scenarios					1-Hour Impacts (μg/m³)		
Case Number	Load (%)	Ambient Temperature (°F)	Annualized Emission Rate (g/s)	Operating Mode	ISCST3 Unadjusted Results*	Emission Rate Factor†	ISCST3 Adjusted Results**
SC-4	100	59	0.702	Simple-Cycle	4.45	0.702	3.12
SC-5	80	59	0.702	Simple-Cycle	7.94	0.702	5.57
SC-6	**60**	**59**	**0.702**	**Simple-Cycle**	**10.62**	**0.702**	**7.46**
					Maximum		**7.46**
CC-4	100	59	0.702	Combined-Cycle	10.79	0.702	7.57
CC-5	80	59	0.702	Combined-Cycle	13.75	0.702	9.65
CC-6	**60**	**59**	**0.702**	**Combined-Cycle**	**16.95**	**0.702**	**11.90**
					Maximum		**11.9**

*Based on 1.0-g/s emission rate.
†Annualized emission rate (in g/s) divided by 1.0 g/s.
**ISCST3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-3. ISCST3 (Screening Mode) Model Results—CO Impacts (Short-Term Operating Scenarios)

Operating Scenarios					1-Hour Impacts (μg/m³)		
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Operating Mode	ISCST3 Unadjusted Results*	Emission Rate Factor†	ISCST3 Adjusted Results**
SC-1	100	20	5.92	Simple-Cycle	3.35	5.92	19.83
SC-2	80	20	4.66	Simple-Cycle	7.03	4.66	32.76
SC-3	60	20	4.03	Simple-Cycle	9.83	4.03	39.61
SC-4	100	59	5.42	Simple-Cycle	4.45	5.42	24.12
SC-5	80	59	4.41	Simple-Cycle	7.94	4.41	35.02
SC-6	60	59	3.78	Simple-Cycle	10.62	3.78	40.14
SC-7	100	95	4.91	Simple-Cycle	5.68	4.91	27.89
SC-8	80	95	4.03	Simple-Cycle	8.95	4.03	36.07
SC-9	**60**	**95**	**3.53**	**Simple-Cycle**	**11.46**	**3.53**	**40.45**
					Maximum		**40.45**
CC-1	100	20	5.92	Combined-Cycle	10.16	5.92	60.15
CC-2	80	20	4.66	Combined-Cycle	12.17	4.66	56.71
CC-3	60	20	4.03	Combined-Cycle	14.66	4.03	59.08
CC-4	100	59	5.42	Combined-Cycle	10.79	5.42	58.48
CC-5	80	59	4.41	Combined-Cycle	13.75	4.41	60.64
CC-6	60	59	3.78	Combined-Cycle	16.95	3.78	64.07
CC-7	100	95	4.91	Combined-Cycle	12.09	4.91	59.36
CC-8	80	95	4.03	Combined-Cycle	15.96	4.03	64.32
CC-9	**60**	**95**	**3.53**	**Combined-Cycle**	**18.79**	**3.53**	**66.33**
					Maximum		**66.33**

*Based on 1.0-g/s emission rate.
†Emission rate (in g/s) divided by 1.0 g/s.
**ISCST3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

Table 7-4. ISCST3 (Screening Mode) Model Results—PM_{10} Impacts (Short-Term Operating Scenarios)

Operating Scenarios					1-Hour Impacts (μg/m³)		
Case Number	Load (%)	Ambient Temperature (°F)	Emission Rate (g/s)	Operating Mode	ISCST3 Unadjusted Results*	Emission Rate Factor†	ISCST3 Adjusted Results**
SC-1	100	20	1.26	Simple-Cycle	3.35	1.26	4.22
SC-2	80	20	1.26	Simple-Cycle	7.03	1.26	8.86
SC-3	60	20	1.26	Simple-Cycle	9.83	1.26	12.39
SC-4	100	59	1.26	Simple-Cycle	4.45	1.26	5.61
SC-5	80	59	1.26	Simple-Cycle	7.94	1.26	10.00
SC-6	60	59	1.26	Simple-Cycle	10.62	1.26	13.38
SC-7	100	95	1.26	Simple-Cycle	5.68	1.26	7.16
SC-8	80	95	1.26	Simple-Cycle	8.95	1.26	11.28
SC-9	**60**	**95**	**1.26**	**Simple-Cycle**	**11.46**	**1.26**	**14.44**
					Maximum		**14.44**
CC-1	100	20	1.26	Combined-Cycle	10.16	1.26	12.8
CC-2	80	20	1.26	Combined-Cycle	12.17	1.26	15.33
CC-3	60	20	1.26	Combined-Cycle	14.66	1.26	18.47
CC-4	100	59	1.26	Combined-Cycle	10.79	1.26	13.6
CC-5	80	59	1.26	Combined-Cycle	13.75	1.26	17.33
CC-6	60	59	1.26	Combined-Cycle	16.95	1.26	21.36
CC-7	100	95	1.26	Combined-Cycle	12.09	1.26	15.23
CC-8	80	95	1.26	Combined-Cycle	15.96	1.26	20.11
CC-9	**60**	**95**	**1.26**	**Combined-Cycle**	**18.79**	**1.26**	**23.68**
					Maximum		**23.68**

*Based on 1.0-g/s emission rate.
†Emission rate (in g/s) divided by 1.0 g/s.
**ISCST3 unadjusted results multiplied by emission rate factor.

Source: ECT, 1999.

cycle short-term (i.e., 1-, 8-, and 24-hour averaging periods) operating scenarios, maximum 1-hour impacts for CO and PM_{10} occurred under Case 9 operating conditions (i.e., 60-percent load and 95°F ambient temperature). These worst case operating cases 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 (1984 to 1988) are summarized for simple-cycle and combined-cycle modes on Tables 7-5 and 7-6 (annual NO_2 impacts), Tables 7-7 and 7-8 (annual PM_{10} impacts), Tables 7-9 and 7-10 (24-hour PM_{10} impacts), Tables 7-11 and 7-12 (1-hour CO impacts), and Tables 7-13 and 7-14 (8-hour CO impacts).

Tables 7-4 through 7-14 demonstrate that repowering project impacts, for all pollutants and all averaging times, are below the PSD significant impact levels previously shown in Table 4-2. Table 7-15 provides a summary of maximum repowering project impacts and PSD significant impact levels.

7.3 PSD CLASS I IMPACTS

Maximum impacts at the Chassahowitzka and Okefenokee NWRs were conservatively estimated using the ISCST3 refined mode dispersion model. For the Chassahowitzka NWR, ISCST3 refined mode model results for each year of meteorology evaluated (1984 to 1988) are summarized for simple-cycle and combined-cycle modes on Tables 7-16 and 7-17 (annual NO_2 impacts), Tables 7-18 and 7-19 (annual PM_{10} impacts), and Tables 7-20 and 7-21 (24-hour PM_{10} impacts). The corresponding ISCST3 model results for the Okefenokee NWR are provided in Tables 7-22 through 7-27. Table 7-28 provides a summary of maximum repowering project Class I area impacts and the EPA PSD Class I area significant impact levels. All modeled impacts are predicted to be well below the EPA PSD Class I significance levels.

Table 7-5. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6

Maximum Annual Impacts	1984	1985	1986	1987	**1988**
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.00198	0.00204	0.00187	0.00202	**0.00224**
Emission Rate Scaling Factor†	5.961	5.961	5.961	5.961	**5.961**
Tier 1 Impact ($\mu g/m^3$)**	0.012	0.012	0.011	0.012	**0.013**
Tier 2 Impact ($\mu g/m^3$)‡	0.009	0.009	0.008	0.009	**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 (%)	0.9	0.9	0.8	0.9	**1.0**
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	14.0	14.0	14.0	**14.0**
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	**N**
Percent of PSD *de minimis* Ambient Impact (%)	0.1	0.1	0.1	0.1	**0.1**
Receptor UTM Easting (m)	367,688.6	380,388.4	365,869.0	363,474.0	**364,680.8**
Receptor UTM Northing (m)	3,284,418.0	3,277,097.0	3,283,675.3	3,277,097.0	**3,283,556.3**
Distance From CC-1 (m)	6,065	8,957	7,054	8,995	**8,049**
Direction From CC-1 (Vector °)	315	110	300	250	**295**

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

Table 7-6. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6

Maximum Annual Impacts	1984	**1985**	1986	1987	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.04411	**0.04931**	0.04084	0.04091	0.04114
Emission Rate Scaling Factor†	5.961	**5.961**	5.961	5.961	5.961
Tier 1 Impact ($\mu g/m^3$)**	0.263	**0.294**	0.243	0.244	0.245
Tier 2 Impact ($\mu g/m^3$)‡	0.197	**0.220**	0.183	0.183	0.184
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 (%)	19.7	**22.0**	18.3	18.3	18.4
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	14.0	**14.0**	14.0	14.0	14.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	**N**	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	1.4	**1.6**	1.3	1.3	1.3
Receptor UTM Easting (m)	372,139.5	**372,138.5**	372,139.5	371,831.9	372,139.5
Receptor UTM Northing (m)	3,280,108.0	**3,280,046.0**	3,280,108.0	3,280,075.0	3,280,108.0
Distance From CC-1 (m)	188	**196**	188	123	188
Direction From CC-1 (Vector °)	89	**107**	89	256	89

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

Table 7-7. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6

Maximum Annual Impacts	1984	1985	1986	1987	**1988**
Unadjusted ISCST3 Impact (μg/m^3)*	0.00198	0.00204	0.00187	0.00202	**0.00224**
Emission Rate Scaling Factor†	0.702	0.702	0.702	0.702	**0.702**
Adjusted Impact (μg/m^3)**	0.0014	0.0014	0.0013	0.0014	**0.0016**
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 (%)	0.1	0.1	0.1	0.1	**0.2**
Receptor UTM Easting (m)	367,688.6	380,388.4	365,869.0	363,474.0	**364,680.8**
Receptor UTM Northing (m)	3,284,418.0	3,277,097.0	3,283,675.3	3,277,097.0	**3,283,556.3**
Distance From CC-1 (m)	6,065	8,957	7,054	8,995	**8,049**
Direction From CC-1 (Vector °)	315	110	300	250	**295**

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

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Table 7-8. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6

Maximum Annual Impacts	1984	**1985**	1986	1987	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.04411	**0.04931**	0.04084	0.04091	0.04114
Emission Rate Scaling Factor†	0.702	**0.702**	0.702	0.702	0.702
Adjusted Impact ($\mu g/m^3$)**	0.031	**0.035**	0.029	0.029	0.029
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 (%)	3.1	**3.5**	2.9	2.9	2.9
Receptor UTM Easting (m)	372,139.5	**372,138.5**	372,139.5	371,831.9	372,139.5
Receptor UTM Northing (m)	3,280,108.0	**3,280,046.0**	3,280,108.0	3,280,075.0	3,280,108.0
Distance From CC-1 (m)	188	**196**	188	123	188
Direction From CC-1 (Vector °)	89	**107**	89	256	89

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-9. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Oil-Firing Case 9

Maximum 24-Hour Impacts	1984	1985	1986	1987	**1988**
Unadjusted ISCST3 Impact (μg/m³)*	0.198	0.040	0.059	0.043	**0.280**
Emission Rate Scaling Factor†	1.26	1.26	1.26	1.26	**1.26**
Adjusted Impact (μg/m³)**	0.25	0.05	0.07	0.05	**0.35**
PSD Significant Impact (μg/m³)	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 (%)	5.0	1.0	1.5	1.1	**7.0**
PSD *de minimis* Ambient Impact Threshold (μg/m³)	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 (%)	2.5	0.5	0.7	0.5	**3.5**
Receptor UTM Easting (m)	371,981.2	373,859.6	372,005.4	374,431.2	**372,136.4**
Receptor UTM Northing (m)	3,280,225.0	3,277,877.3	3,280,216.0	3,275,845.3	**3,280,159.0**
Distance From CC-1 (m)	124	2,932	124	4,928	**193**
Direction From CC-1 (Vector °)	14	139	26	150	**73**
Date of Maximum Impact	3/20/84	7/8/85	7/30/86	8/8/87	**4/12/88**
Julian Date of Maximum Impact	80	189	211	220	**103**

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-10. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Oil-Firing, Case 9

Maximum 24-Hour Impacts	**1984**	1985	1986	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	**1.651**	1.246	0.880	1.054	1.262
Emission Rate Scaling Factor†	**1.26**	1.26	1.26	1.26	1.26
Adjusted Impact (μg/m^3)**	**2.08**	1.57	1.11	1.33	1.59
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 (%)	**41.6**	31.4	22.2	26.6	31.8
PSD *de minimis* Ambient Impact Threshold (μg/m^3)	**10.0**	10.0	10.0	10.0	10.0
Exceed PSD *de minimis* Ambient Impact (Y/N)	**N**	N	N	N	N
Percent of PSD *de minimis* Ambient Impact (%)	**20.8**	15.7	11.1	13.3	15.9
Receptor UTM Easting (m)	**372,157.8**	371,881.2	372,139.5	371,825.5	372,110.0
Receptor UTM Northing (m)	**3,280,069.8**	3,280,126.0	3,280,108.0	3,279,948.8	3,279,998.5
Distance From CC-1 (m)	**209**	74	188	200	190
Direction From CC-1 (Vector °)	**99**	287	89	219	124
Date of Maximum Impact	**2/28/84**	8/31/85	3/6/86	3/6/87	3/14/88
Julian Date of Maximum Impact	**59**	243	65	65	74

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-11. ISCST3 Model Results - 1-Hour Average CO Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Oil-Firing, Case 9

Maximum 1-Hour Impacts	**1984**	1985	1986	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	**4.160**	0.833	1.419	0.547	3.966
Emission Rate Scaling Factor†	**3.530**	3.530	3.530	3.530	3.530
Adjusted Impact (μg/m^3)**	**14.69**	2.94	5.01	1.93	14.00
PSD Significant Impact (μg/m^3)	**2,000.0**	2,000.0	2,000.0	2,000.0	2,000.0
Exceed PSD Significant Impact (Y/N)	**N**	N	N	N	N
Percent of PSD Significant Impact (%)	**0.7**	0.1	0.3	0.1	0.7
Receptor UTM Easting (m)	**371,981.2**	372,139.5	372,005.4	371,400.9	372,136.4
Receptor UTM Northing (m)	**3,280,225.0**	3,280,108.0	3,280,216.0	3,279,645.0	3,280,159.0
Distance From CC-1 (m)	**124**	188	124	717	193
Direction From CC-1 (Vector °)	**14**	89	26	230	73
Date of Maximum Impact	**3/20/84**	1/28/85	7/30/86	7/25/87	4/12/88
Julian Date of Maximum Impact	**80**	28	211	206	103
Ending Hour of Maximum Impact	**1800**	1600	0200	1500	1200

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-12. ISCST3 Model Results - 1-Hour Average CO Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Oil-Firing, Case 9

Maximum 1-Hour Impacts	**1984**	1985	1986	1987	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	**12.213**	7.959	7.343	7.862	8.772
Emission Rate Scaling Factor†	**3.530**	3.530	3.530	3.530	3.530
Adjusted Impact ($\mu g/m^3$)**	**43.11**	28.09	25.92	27.75	30.97
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 (%)	**2.2**	1.4	1.3	1.4	1.5
Receptor UTM Easting (m)	**371,981.2**	372,016.5	371,981.2	371,981.2	372,108.0
Receptor UTM Northing (m)	**3,280,225.0**	3,280,030.0	3,280,225.0	3,280,025.0	3,279,998.5
Distance From CC-1 (m)	**124**	98	124	84	189
Direction From CC-1 (Vector °)	**14**	139	14	160	124
Date of Maximum Impact	**3/20/84**	5/20/85	7/30/86	12/4/87	11/28/88
Julian Date of Maximum Impact	**80**	140	211	338	333
Ending Hour of Maximum Impact	**1800**	1600	0200	1100	0600

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-13. ISCST3 Model Results - 8-Hour Average CO Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Oil-Firing, Case 9

Maximum 8-Hour Impacts	1984	1985	1986	1987	**1988**
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.520	0.109	0.177	0.101	**0.699**
Emission Rate Scaling Factor†	3.530	3.530	3.530	3.530	**3.530**
Adjusted Impact ($\mu g/m^3$)**	1.84	0.38	0.63	0.35	**2.47**
PSD Significant Impact ($\mu g/m^3$)	500.0	500.0	500.0	500.0	**500.0**
Exceed PSD Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	0.4	0.1	0.1	0.1	**0.5**
PSD *de minimis* Ambient Impact Threshold ($\mu g/m^3$)	575.0	575.0	575.0	575.0	**575.0**
Exceed PSD *de minimis* Ambient Impact (Y/N)	N	N	N	N	**N**
Percent of PSD *de minimis* Ambient Impact (%)	0.3	0.1	0.1	0.1	**0.4**
Receptor UTM Easting (m)	371,981.2	372,139.5	372,005.4	372,053.2	**372,136.4**
Receptor UTM Northing (m)	3,280,225.0	3,280,108.0	3,280,216.0	3,281,570.0	**3,280,159.0**
Distance From CC-1 (m)	124	188	124	1,469	**193**
Direction From CC-1 (Vector ^{o})	14	89	26	4	**73**
Date of Maximum Impact	3/20/84	1/28/85	7/30/86	7/7/87	**4/12/88**
Julian Date of Maximum Impact	80	28	211	188	**103**
Ending Hour of Maximum Impact	2400	1600	0800	1600	**1600**

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-14. ISCST3 Model Results - 8-Hour Average CO Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Oil-Firing, Case 9

Maximum 8-Hour Impacts	1984	**1985**	1986	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	2.538	**2.361**	2.023	1.840	2.101
Emission Rate Scaling Factor†	3.530	**3.530**	3.530	3.530	3.530
Adjusted Impact (μg/m^3)**	8.96	**8.33**	7.14	6.50	7.42
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 (%)	1.8	**1.7**	1.4	1.3	1.5
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 (%)	1.6	**1.4**	1.2	1.1	1.3
Receptor UTM Easting (m)	372,081.2	**371,881.2**	372,138.5	372,136.4	372,108.0
Receptor UTM Northing (m)	3,280,275.0	**3,280,126.0**	3,280,046.0	3,280,159.0	3,279,998.5
Distance From CC-1 (m)	214	**74**	196	193	189
Direction From CC-1 (Vector °)	37	**287**	107	73	124
Date of Maximum Impact	3/28/84	**8/31/85**	1/27/86	4/16/87	3/14/88
Julian Date of Maximum Impact	88	**243**	27	106	74
Ending Hour of Maximum Impact	1600	**1600**	1600	1600	1600

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

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Table 7-15. ISCST3 Model Results—Maximum Criteria Pollutant Impacts

A. Simple-Cycle Mode

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.01	1.0
CO	8-hour	2.5	500
	1-hour	14.7	2,000
PM_{10}	Annual	0.002	1.0
	24-hour	0.4	5.0

B. Combined-Cycle Mode

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.2	1.0
CO	8-hour	8.3	500
	1-hour	43.1	2,000
PM_{10}	Annual	0.04	1.0
	24-hour	2.1	5.0

Source: ECT, 1999.

Table 7-16. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6 Chassowitzka NWR

Maximum Annual Impacts	1984	1985	**1986**	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	0.00037	0.00031	**0.00042**	0.00033	0.00027
Emission Rate Scaling Factor†	5.961	5.961	**5.961**	5.961	5.961
Tier 1 Impact (μg/m^3)**	0.002	0.002	**0.003**	0.002	0.002
Tier 2 Impact (μg/m^3)‡	0.002	0.001	**0.002**	0.001	0.001
PSD Class I Significant Impact (μg/m^3)	0.1	0.1	**0.1**	0.1	0.1
Exceed PSD Class I Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	1.7	1.4	**1.9**	1.5	1.2
Receptor UTM Easting (m)	341,100.0	343,700.0	**341,100.0**	343,700.0	341,100.0
Receptor UTM Northing (m)	3,183,400.0	3,178,300.0	**3,183,400.0**	3,178,300.0	3,183,400.0
Distance From CC-1 (m)	101,506	105,651	**101,506**	105,651	101,506
Direction From CC-1 (Vector °)	198	196	**198**	196	198

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

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Table 7-17. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6 Chassowitzka NWR

Maximum Annual Impacts	1984	1985	1986	1987	1988
Unadjusted ISCST3 Impact (µg/m^3)*	0.00067	0.00063	**0.00091**	0.00061	0.00053
Emission Rate Scaling Factor†	5.961	5.961	**5.961**	5.961	5.961
Tier 1 Impact (µg/m^3)**	0.004	0.004	**0.005**	0.004	0.003
Tier 2 Impact (µg/m^3)‡	0.003	0.003	**0.004**	0.003	0.002
PSD Class I Significant Impact (µg/m^3)	0.1	0.1	**0.1**	0.1	0.1
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	3.0	2.8	**4.1**	2.7	2.4
Receptor UTM Easting (m)	336,500.0	343,700.0	**341,100.0**	339,000.0	339,000.0
Receptor UTM Northing (m)	3,183,400.0	3,178,300.0	**3,183,400.0**	3,183,400.0	3,183,400.0
Distance From CC-1 (m)	102,998	105,651	**101,506**	102,164	102,164
Direction From CC-1 (Vector °)	200	196	**198**	199	199

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

Table 7-18. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6 Chassowitzka NWR

Maximum Annual Impacts	1984	1985	1986	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	0.00037	0.00031	**0.00042**	0.00033	0.00027
Emission Rate Scaling Factor†	0.702	0.702	**0.702**	0.702	0.702
Adjusted Impact (μg/m^3)**	0.00026	0.00022	**0.00029**	0.00023	0.00019
PSD Class I Significant Impact (μg/m^3)	0.2	0.2	**0.2**	0.2	0.2
Exceed PSD Class I Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	0.1	0.1	**0.1**	0.1	0.1
Receptor UTM Easting (m)	341,100.0	343,700.0	**341,100.0**	343,700.0	341,100.0
Receptor UTM Northing (m)	3,183,400.0	3,178,300.0	**3,183,400.0**	3,178,300.0	3,183,400.0
Distance From CC-1 (m)	101,506	105,651	**101,506**	105,651	101,506
Direction From CC-1 (Vector °)	198	196	**198**	196	198

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate scaling factor .

Source: ECT, 1999.

Table 7-19. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6 Chassowitzka NWR

Maximum Annual Impacts	1984	1985	**1986**	1987	1988
Unadjusted ISCST3 Impact (µg/m^3)*	0.00067	0.00063	**0.00091**	0.00061	0.00053
Emission Rate Scaling Factor†	0.702	0.702	**0.702**	0.702	0.702
Adjusted Impact (µg/m^3)**	0.00047	0.00044	**0.00064**	0.00043	0.00037
PSD Class I Significant Impact (µg/m^3)	0.2	0.2	**0.2**	0.2	0.2
Exceed PSD Class I Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	0.2	0.2	**0.3**	0.2	0.2
Receptor UTM Easting (m)	336,500.0	343,700.0	**341,100.0**	339,000.0	339,000.0
Receptor UTM Northing (m)	3,183,400.0	3,178,300.0	**3,183,400.0**	3,183,400.0	3,183,400.0
Distance From CC-1 (m)	102,998	105,651	**101,506**	102,164	102,164
Direction From CC-1 (Vector °)	200	196	**198**	199	199

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate scaling factor .

Source: ECT, 1999.

Table 7-20. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Oil-Firing, Case 6, Chassowitzka NWR

Maximum 24-Hour Impacts	1984	1985	1986	**1987**	1988
Unadjusted ISCST3 Impact (μg/m³)*	0.0081	0.0067	0.0079	**0.0089**	0.0076
Emission Rate Scaling Factor†	1.26	1.26	1.26	**1.26**	1.26
Adjusted Impact (μg/m³)**	0.01	0.01	0.01	**0.01**	0.01
PSD Class I Significant Impact (μg/m³)	0.3	0.3	0.3	**0.3**	0.3
Exceed PSD Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	3.4	2.8	3.3	**3.7**	3.2
Receptor UTM Easting (m)	341,100.0	342,400.0	336,500.0	**334,000.0**	341,100.0
Receptor UTM Northing (m)	3,183,400.0	3,180,600.0	3,183,400.0	**3,183,400.0**	3,183,400.0
Distance From CC-1 (m)	101,506	103,800	102,998	**103,885**	101,506
Direction From CC-1 (Vector °)	198	197	200	**201**	198
Date of Maximum Impact	9/20/84	10/25/85	12/7/86	**12/6/87**	11/11/88
Julian Date of Maximum Impact	264	298	341	**340**	316

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-21. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Oil-Firing, Case 6, Chassowitzka NWR

Maximum 24-Hour Impacts	1984	1985	1986	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	0.0125	0.0138	0.0138	0.0119	0.0141
Emission Rate Scaling Factor†	1.26	1.26	1.26	1.26	1.26
Adjusted Impact (μg/m^3)**	0.02	0.02	0.02	0.02	0.02
PSD Class I Significant Impact (μg/m^3)	0.3	0.3	0.3	0.3	0.3
Exceed PSD Significant Impact (Y/N)	N	N	N	N	N
Percent of PSD Significant Impact (%)	5.3	5.8	5.8	5.0	5.9
Receptor UTM Easting (m)	342,400.0	341,100.0	341,100.0	334,000.0	341,100.0
Receptor UTM Northing (m)	3,180,600.0	3,183,400.0	3,183,400.0	3,183,400.0	3,183,400.0
Distance From CC-1 (m)	103,800	101,506	101,506	103,885	101,506
Direction From CC-1 (Vector °)	197	198	198	201	198
Date of Maximum Impact	10/25/84	10/25/85	12/4/86	12/6/87	11/11/88
Julian Date of Maximum Impact	299	298	338	340	316

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-22. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6 Okefenokee NWR

Maximum Annual Impacts	1984	1985	1986	**1987**	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.00029	0.00032	0.00032	**0.00034**	0.00026
Emission Rate Scaling Factor†	5.961	5.961	5.961	**5.961**	5.961
Tier 1 Impact ($\mu g/m^3$)**	0.002	0.002	0.002	**0.002**	0.002
Tier 2 Impact ($\mu g/m^3$)‡	0.001	0.001	0.001	**0.002**	0.001
PSD Class I Significant Impact ($\mu g/m^3$)	0.1	0.1	0.1	**0.1**	0.1
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	1.3	1.4	1.4	**1.5**	1.2
Receptor UTM Easting (m)	378,000.0	370,000.0	370,000.0	**370,000.0**	370,000.0
Receptor UTM Northing (m)	3,382,000.0	3,383,000.0	3,383,000.0	**3,383,000.0**	3,383,000.0
Distance From CC-1 (m)	102,075	102,914	102,914	**102,914**	102,914
Direction From CC-1 (Vector °)	3	359	359	**359**	359

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

Table 7-23. ISCST3 Model Results - Annual Average NO_2 Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6 Okefenokee NWR

Maximum Annual Impacts	1984	1985	**1986**	1987	1988
Unadjusted ISCST3 Impact (μg/m^3)*	0.00048	0.00058	**0.00060**	0.00060	0.00045
Emission Rate Scaling Factor†	5.961	5.961	**5.961**	5.961	5.961
Tier 1 Impact (μg/m^3)**	0.003	0.003	**0.004**	0.004	0.003
Tier 2 Impact (μg/m^3)‡	0.002	0.003	**0.003**	0.003	0.002
PSD Class I Significant Impact (μg/m^3)	0.1	0.1	**0.1**	0.1	0.1
Exceed PSD Class I Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	2.1	2.6	**2.7**	2.7	2.0
Receptor UTM Easting (m)	370,000.0	370,000.0	**370,000.0**	374,000.0	370,000.0
Receptor UTM Northing (m)	3,383,000.0	3,383,000.0	**3,383,000.0**	3,383,000.0	3,383,000.0
Distance From CC-1 (m)	102,914	102,914	**102,914**	102,916	102,914
Direction From CC-1 (Vector °)	359	359	**359**	1	359

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor (Assumed complete conversion of NO_x to NO_2; i.e., NO_2/NO_x ratio of 1.0).

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

Source: ECT, 1999.

Table 7-24. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Case 6 Okefenokee NWR

Maximum Annual Impacts	1984	1985	1986	**1987**	1988
Unadjusted ISCST3 Impact (μg/m^3)*	0.00029	0.00032	0.00032	**0.00034**	0.00026
Emission Rate Scaling Factor†	0.702	0.702	0.702	**0.702**	0.702
Adjusted Impact (μg/m^3)**	0.00020	0.00022	0.00022	**0.00024**	0.00018
PSD Class I Significant Impact (μg/m^3)	0.2	0.2	0.2	**0.2**	0.2
Exceed PSD Class I Significant Impact (Y/N)	N	N	N	**N**	N
Percent of PSD Significant Impact (%)	0.1	0.1	0.1	**0.1**	0.1
Receptor UTM Easting (m)	378,000.0	370,000.0	370,000.0	**370,000.0**	370,000.0
Receptor UTM Northing (m)	3,382,000.0	3,383,000.0	3,383,000.0	**3,383,000.0**	3,383,000.0
Distance From CC-1 (m)	102,075	102,914	102,914	**102,914**	102,914
Direction From CC-1 (Vector °)	3	359	359	**359**	359

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate scaling factor .

Source: ECT, 1999.

Table 7-25. ISCST3 Model Results - Annual Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Case 6 Okefenokee NWR

Maximum Annual Impacts	1984	1985	**1986**	1987	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.00048	0.00058	**0.00060**	0.00060	0.00045
Emission Rate Scaling Factor†	0.702	0.702	**0.702**	0.702	0.702
Adjusted Impact ($\mu g/m^3$)**	0.00034	0.00041	**0.00042**	0.00042	0.00032
PSD Class I Significant Impact ($\mu g/m^3$)	0.2	0.2	**0.2**	0.2	0.2
Exceed PSD Class I Significant Impact (Y/N)	N	N	**N**	N	N
Percent of PSD Significant Impact (%)	0.2	0.2	**0.2**	0.2	0.2
Receptor UTM Easting (m)	370,000.0	370,000.0	**370,000.0**	374,000.0	370,000.0
Receptor UTM Northing (m)	3,383,000.0	3,383,000.0	**3,383,000.0**	3,383,000.0	3,383,000.0
Distance From CC-1 (m)	102,914	102,914	**102,914**	102,916	102,914
Direction From CC-1 (Vector °)	359	359	**359**	1	359

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate scaling factor .

Source: ECT, 1999.

Table 7-26. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, SC-1, Oil-Firing, Case 9, Okefenokee NWR

Maximum 24-Hour Impacts	1984	1985	1986	1987	**1988**
Unadjusted ISCST3 Impact (µg/m^3)*	0.0060	0.0086	0.0076	0.0059	**0.0086**
Emission Rate Scaling Factor†	1.26	1.26	1.26	1.26	**1.26**
Adjusted Impact (µg/m^3)**	0.01	0.01	0.01	0.01	**0.01**
PSD Class I Significant Impact (µg/m^3)	0.3	0.3	0.3	0.3	**0.3**
Exceed PSD Significant Impact (Y/N)	N	N	N	N	**N**
Percent of PSD Significant Impact (%)	2.5	3.6	3.2	2.5	**3.6**
Receptor UTM Easting (m)	374,000.0	378,000.0	383,000.0	374,000.0	**378,000.0**
Receptor UTM Northing (m)	3,383,000.0	3,382,000.0	3,384,000.0	3,383,000.0	**3,382,000.0**
Distance From CC-1 (m)	102,916	102,075	104,482	102,916	**102,075**
Direction From CC-1 (Vector °)	1	3	6	1	**3**
Date of Maximum Impact	7/1/84	4/6/85	5/29/86	8/16/87	**9/4/88**
Julian Date of Maximum Impact	183	96	149	228	**248**

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-27. ISCST3 Model Results - 24-Hour Average PM_{10} Impacts, J.R. Kelly Generating Station Repowering Project, CC-1, Oil-Firing, Case 9, Okefenokee NWR

Maximum 24-Hour Impacts	1984	**1985**	1986	1987	1988
Unadjusted ISCST3 Impact ($\mu g/m^3$)*	0.0108	**0.0134**	0.0126	0.0121	0.0119
Emission Rate Scaling Factor†	1.26	**1.26**	1.26	1.26	1.26
Adjusted Impact ($\mu g/m^3$)**	0.01	**0.02**	0.02	0.02	0.02
PSD Class I Significant Impact ($\mu g/m^3$)	0.3	**0.3**	0.3	0.3	0.3
Exceed PSD Significant Impact (Y/N)	N	**N**	N	N	N
Percent of PSD Significant Impact (%)	4.5	**5.6**	5.3	5.1	5.0
Receptor UTM Easting (m)	378,000.0	**370,000.0**	383,000.0	374,000.0	378,000.0
Receptor UTM Northing (m)	3,382,000.0	**3,382,000.0**	3,384,000.0	3,383,000.0	3,382,000.0
Distance From CC-1 (m)	102,075	**101,915**	104,482	102,916	102,075
Direction From CC-1 (Vector °)	3	**359**	6	1	3
Date of Maximum Impact	7/5/84	**4/6/85**	5/29/86	6/20/87	9/4/88
Julian Date of Maximum Impact	187	**96**	149	171	248

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

†Ratio of maximum emission rate (g/s) to modeled 1.0 g/s emission rate.

**Unadjusted ISCST3 impact times emission rate factor.

Source: ECT, 1999.

Table 7-28. ISCST3 Model Results—Maximum Class I Area Impacts

A. Okefenokee NWR

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	EPA Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.003	0.1
PM_{10}	Annual	0.0004	0.2
	24-hour	0.02	0.3

B. Chassahowitzka NWR

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	EPA Significant Impact ($\mu g/m^3$)
NO_x	Annual	0.004	0.1
PM_{10}	Annual	0.0006	0.2
	24-hour	0.02	0.3

Note: Maximum Class I impacts occur for combined-cycle mode operations.

Source: ECT, 1999.

The Okefenokee NWR is located approximately 103 km north of the J.R. Kelly Generating Station. The Chassahowitzka NWR is located approximately 102 km southwest of the J.R. Kelly Generating Station. Accordingly, use of the ISCST3 dispersion model to predict impacts at these Class I areas will yield conservative results (i.e., over-estimate actual impacts). In addition, short-term impacts were developed assuming fuel oil firing operating conditions. Maximum Class I impacts during natural gas firing will be significantly lower. As stated previously, the new CTG will operate with a fuel oil annual capacity factor of 11.4 percent (i.e., no more 1,000 hr/yr at base load).

7.4 TOXIC AIR POLLUTANT ASSESSMENT

Although no longer required by FDEP for permitting purposes, an evaluation of toxic air pollutant impacts was conducted using the ISCST3 (refined mode) model results and Version 4.0 of FDEP's Ambient Reference Concentration (ARC) list. The ARCs, which were derived from occupational standards applicable to healthy workers, include safety factors to extend their applicability to the general public. Accordingly, the ARCs represent toxic air pollutant ambient air concentrations considered acceptable for general public exposure by FDEP.

Maximum repowering project air quality impacts are predicted to occur under Case 9 operating conditions (i.e., 60-percent load and 95°F ambient temperatures). Toxic air pollutant emission rates for the new CTG are directly proportional to fuel consumption rates. Estimates of maximum toxic air pollutant impacts were based on maximum emission rates and ISCST3 model results under Case 9 operating conditions. The specific toxic air pollutants emitted by the new CTG were previously provided in Tables 2-3, 2-4, and 2-5. Maximum toxic air pollutant impacts are summarized in Table 7-29.

7.5 CONCLUSIONS

Comprehensive dispersion modeling using the screening mode and refined mode ISCST3 models demonstrates that the repowering project will result in ambient air quality impacts that are:

- Below PSD Class I and Class II significant impact levels for all pollutants and all averaging periods.

Table 7-29. ISCST3 Model Results - Toxic Air Pollutants

A. Model Results Based on 1.0 g/s Emission Rate

	Averaging Period		
	8-Hr	24-Hr	Annual
Maximum Impact (μg/m^3) (Case 9, Oil-Firing)	5.95	2.44	0.0857

B. Toxic Air Pollutant Impacts

	Emission Rate*	Maximum Impact (μg/m^3)			FDEP ARC (μg/m^3)			Percent of FDEP ARC (%)		
Pollutant	(g/s)	8-Hr	24-Hr	Annual	8-Hr	24-Hr	Annual	8-Hr	24-Hr	Annual
Acetaldehyde	1.16E-03	6.89E-03	2.83E-03	9.92E-05	4.50E+02	1.07E+02	5.00E-01	0.0015	0.0026	0.0198
Antimony	3.11E-03	1.85E-02	7.59E-03	2.66E-04	5.00E+00	1.20E+00	3.00E-01	0.3698	0.6323	0.0887
Arsenic	6.92E-04	4.12E-03	1.69E-03	5.93E-05	1.00E-01	2.00E-02	2.30E-04	4.1181	8.4503	25.7769
Benzene	1.98E-04	1.18E-03	4.83E-04	1.69E-05	3.00E+01	7.00E+00	1.20E-01	0.0039	0.0069	0.0141
Beryllium	4.66E-05	2.77E-04	1.14E-04	3.99E-06	2.00E-02	5.00E-03	4.20E-04	1.3867	2.2764	0.9507
Cadmium	5.93E-04	3.53E-03	1.45E-03	5.08E-05	2.00E-02	5.00E-03	5.60E-04	17.6488	28.9724	9.0745
Chromium VI	1.31E-04	7.80E-04	3.20E-04	1.12E-05	5.00E-01	1.00E-01	8.30E-05	0.1559	0.3199	13.5224
Chromium	6.64E-03	3.95E-02	1.62E-02	5.69E-04	5.00E+00	1.20E+00	1.00E+03	0.7900	1.3509	0.0001
Cobalt	1.28E-03	7.65E-03	3.14E-03	1.10E-04	5.00E-01	1.00E-01	N/A	1.5296	3.1387	N/A
Dioxins/Furans	1.24E-07	7.39E-07	3.03E-07	1.06E-08	N/A	N/A	2.20E-08	N/A	N/A	48.3425
Ethylbenzene	6.92E-05	4.12E-04	1.69E-04	5.93E-06	4.34E+03	1.03E+03	1.00E+03	0.00001	0.00002	0.000001
Formaldehyde	4.24E-03	2.52E-02	1.03E-02	3.63E-04	3.70E+00	9.00E-01	7.70E-02	0.6814	1.1497	0.4714
Hydrogen Chloride	3.25E-01	1.93E+00	7.93E-01	2.78E-02	7.00E+01	1.70E+01	7.00E+00	2.7614	4.6664	0.3976
Hydrogen Fluoride	1.98E-02	1.18E-01	4.83E-02	1.69E-03	2.60E+01	6.20E+00	N/A	0.4525	0.7788	N/A
Lead	8.19E-03	4.87E-02	2.00E-02	7.02E-04	5.00E-01	1.00E-01	9.00E-02	9.7489	20.0048	0.7797
Manganese	4.80E-02	2.86E-01	1.17E-01	4.11E-03	5.00E+01	1.20E+01	5.00E-02	0.5715	0.9772	8.2276
Methyl Chloroform	1.07E-03	6.39E-03	2.62E-03	9.20E-05	1.90E+04	4.52E+03	N/A	0.00003	0.0001	N/A
Methylene Chloride	4.55E-03	2.71E-02	1.11E-02	3.90E-04	1.74E+03	4.14E+02	2.00E+00	0.0016	0.0027	0.0195
Mercury	1.28E-04	7.65E-04	3.14E-04	1.10E-05	1.00E-01	2.00E-02	3.00E-01	0.7648	1.5693	0.0037
Naphthalene	9.14E-05	5.44E-04	2.23E-04	7.83E-06	5.00E+02	1.19E+02	N/A	0.0001	0.0002	N/A
Nickel	5.79E-02	3.45E-01	1.41E-01	4.96E-03	1.00E+00	2.00E-01	N/A	34.4572	70.7066	N/A
Phenol	3.43E-03	2.04E-02	8.38E-03	2.94E-04	1.90E+02	4.50E+01	3.00E+01	0.0107	0.0186	0.0010
Phosphorus	4.24E-02	2.52E-01	1.03E-01	3.63E-03	1.00E+00	2.00E-01	N/A	25.2126	51.7365	N/A
Polycyclic Organic Matter	9.52E-05	5.66E-04	2.32E-04	8.15E-06	N/A	N/A	N/A	N/A	N/A	N/A
Selenium	7.48E-04	4.45E-03	1.83E-03	6.41E-05	2.00E+00	5.00E-01	N/A	0.2227	0.3656	N/A
Tetrachloroethylene	7.77E-05	4.62E-04	1.90E-04	6.65E-06	1.70E+03	4.05E+02	2.10E+00	0.00003	0.00005	0.0003
Toluene	1.39E-03	8.28E-03	3.40E-03	1.19E-04	1.88E+03	4.48E+02	4.00E+02	0.0004	0.0008	0.00003
Vinyl Acetate	7.27E-04	4.33E-03	1.78E-03	6.23E-05	3.50E+02	8.30E+01	2.00E+02	0.0012	0.0021	0.00003
Xylenes	3.09E-04	1.84E-03	7.55E-04	2.65E-05	4.34E+03	1.03E+03	8.00E+01	0.00004	0.0001	0.00003

*Maximum of natural gas or distillate fuel oil emission rates.

Source: ECT, 1999.

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- Below PSD *de minimis* ambient impact levels for all pollutants and all averaging periods.
- Below the FDEP ARCs for all emitted toxic air pollutants.

8.0 AMBIENT AIR QUALITY MONITORING AND ANALYSIS

8.1 EXISTING AMBIENT AIR QUALITY MONITORING DATA

The nearest FDEP ambient air monitoring station is located in Gainesville, Alachua County, approximately 2 km northwest of the project site. This FDEP monitoring station situated near downtown Gainesville monitors PM_{10}. In addition, FDEP has another PM_{10} monitoring station in Gainesville located approximately 14 km northwest of the project site. The nearest FDEP station that monitors O_3 is also located in Gainesville, approximately 12 km south of the project site. The nearest FDEP stations that monitor SO_2, NO_x, lead, and CO are all located in Jacksonville, Duval County, approximately 101 km northeast of the project site. A summary of 1997 and 1998 ambient air quality data for these FDEP stations is provided in Tables 8-1 and 8-2.

Recently, a $PM_{2.5}$ monitor was installed at the northwest Gainesville PM_{10} monitoring location. This additional sampler began collecting data in January 1999. However, in a telephone conversation with FDEP on August 12th, the agency advised that data from this $PM_{2.5}$ site are being processed and currently not available. FDEP indicated there are also plans to locate an additional $PM_{2.5}$ monitor off Tower Road (Southwest 75th Street) in Gainesville during the third quarter of 1999 and an additional ozone monitor sometime in the year 2000.

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 repowering project 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

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

Pollutant	Site Location		Site No.	Relative to Project Site	Averaging	Sampling	No. of	Ambient Concentration (ug/m^3)				
	County	City		(km)	Period	Period	Observations	1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Alachua	Gainesville	1420-003-F01	2 NW	24-Hr	Jan-Dec	60	45	39	45		150*
					Annual						20	50†
			1420-023-F02	14 NW	24-Hr	Jan-Dec	63	75	41	75		150*
					Annual						21	50†
SO_2	Duval	Jacksonville	1960-032-H02	101 NE	1-Hr	Jan-Dec	8,479	157	152			
					3-Hr			134	122			1,300**
					24-Hr			82	47			260**
					Annual						6	60†
			1960-080-H02	101 NE	1-Hr	Jan-Dec	8,514	257	173			
					3-Hr			115	107			1,300**
					24-Hr			51	44			260**
					Annual						5	60†
NO_2	Duval	Jacksonville	1960-032-H02	101 NE	1-Hr	Jan-Dec	8,326	173	130			
					Annual						27	100†
CO	Duval	Jacksonville	1960-080-H01	101 NE	1-Hr	Jan-Dec	8,519	3,420	3,420			40,000**
					8-Hr			2,280	2,280			10,000**
CO			1960-083-H01	101 NE	1-Hr	Jan-Dec	8,544	7,980	5,700			40,000**
					8-Hr			3,420	3,420			10,000**
CO			1960-084-H01	101 NE	1-Hr	Jan-Dec	8,576	6,840	6,840			40,000**
					8-Hr			4,560	3,420			10,000**
CO			1960-095-H01	101 NE	1-Hr	Jan-Dec	8,074	7,980	5,700			40,000**
					8-Hr			3,420	3,420			10,000**
O_3	Alachua	Gainesville	12-001-3011	12 S	1-Hr	Sep-Dec	122 (days)	202	182			235‡
Lead	Duval	Jacksonville	1960-032-H01	101 NE	24-Hr							
						Jan-Mar	15				0.0	1.5†
						Apr-Jun	15				0.0	
						Jul-Sep	15				0.0	
						Oct-Dec	13				0.0	
Lead	Duval	Jacksonville	1960-084-H01	101 NE	24-Hr							
						Jan-Mar	15				0.0	1.5†
						Apr-Jun	15				0.0	
						Jul-Sep	14				0.0	
						Oct-Dec	14				0.0	

*99th percentile.
†Arithmetic mean.
**2nd high.
‡4th highest day with hourly value exceeding standard over a 3-year period.

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

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

Pollutant	Site Location: County	Site Location: City	Site No.	Relative to Project Site (km)	Averaging Period	Sampling Period	No. of Observations	Ambient Concentration (ug/m^3): 1st High	2nd High	99th Percentile	Arithmetic Mean	Standard
PM_{10}	Alachua	Gainesville	12-001-0023	2 NW	24-Hr	Jan-Dec	57	71	51	71		150*
					Annual						22	50†
			12-001-1003	14 NW	24-Hr	Jan-Dec	57	78	53	78		150*
					Annual						23	50†
SO_2	Duval	Jacksonville	12-031-0032	101 NE	1-Hr	Jan-Dec	8,290	342	290			
					3-Hr			257	212			1,300**
					24-Hr			104	97			260**
					Annual						10	60†
			12-031-0080	101 NE	1-Hr	Jan-Dec	8,356	308	256			
					3-Hr			131	128			1,300**
					24-Hr			50	42			260**
					Annual						5	60†
NO_2	Duval	Jacksonville	12-031-0032	101 NE	1-Hr	Jan-Dec	8,204	124	124			
					Annual						28	100†
CO	Duval	Jacksonville	12-031-0080	101 NE	1-Hr	Jan-Dec	8,311	9,576	7,296			40,000**
					8-Hr			5,130	3,306			10,000**
CO			12-031-0083	101 NE	1-Hr	Jan-Dec	8,013	5,586	5,472			40,000**
					8-Hr			3,534	3,306			10,000**
CO			12-031-0084	101 NE	1-Hr	Jan-Dec	8,417	6,954	6,270			40,000**
					8-Hr			3,762	3,762			10,000**
CO			12-031-0095	101 NE	1-Hr	Jan-Dec	2,111	5,016	4,218			40,000**
					8-Hr			2,280	2166			10,000**
O_3	Alachua	Gainesville	12-001-3011	12 S	1-Hr	Jan-Dec	357 (days)	248	224			235‡
Lead	Duval	Jacksonville	12-031-0032	101 NE	24-Hr		50					
						Jan-Mar					0.01	1.5†
						Apr-Jun					0.02	
						Jul-Sep					0.01	
						Oct-Dec					0.02	
Lead	Duval	Jacksonville	12-031-0084	101 NE	24-Hr		62					
						Jan-Mar					0.01	1.5†
						Apr-Jun					0.01	
						Jul-Sep					0.01	
						Oct-Dec					0.02	

*99th percentile
†Arithmetic mean
**2nd high
‡4th highest day with hourly value exceeding standard over a 3-year period

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

emissions from the proposed facility. 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 2.1 μg/m^3. This concentration is below the 10 μg/m^3 *de minimis* level ambient impact level. Therefore, a preconstruction monitoring exemption for PM_{10} is appropriate in accordance with the PSD regulations.

8.2.2 CO

The maximum 8-hour CO impact was predicted to be 8.3 μg/m^3. This concentration is below the 575-μg/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 0.2 μg/m^3. This concentration is below the 14-μg/m^3 *de minimis* ambient impact level. Therefore, a preconstruction monitoring exemption is appropriate for NO_2 in accordance with the FDEP PSD regulations.

9.0 ADDITIONAL IMPACT ANALYSES

The additional impacts analysis, required for repowering projects subject to PSD review, evaluates repowering project impacts pertaining to associated growth; soils, vegetation, and wildlife; and 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 repowering project and assess air quality impacts that would result from that growth.

Impacts associated with construction of the J.R. Kelly Generating Station Repowering Project will be minor. While not readily quantifiable, the temporary increase in vehicle miles traveled in the area would be insignificant, as would any temporary increase in vehicular emissions.

The new CTG is being constructed to meet general area electric power demands; therefore, no significant secondary growth effects due to operation of the repowering project are anticipated. When operational, the new CTG is projected to generate approximately one or two new jobs; this number of new personnel will not significantly affect growth in the area. The increase in natural gas and distillate fuel oil demand due to operation of the new CTG 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 SOILS, VEGETATION, AND WILDLIFE

Maximum air quality impacts in the vicinity of the repowering project due to operation of the proposed new CTG are well below applicable AAQS. Accordingly, no significant, adverse impacts on soils, vegetation, and wildlife in the vicinity of the J.R. Kelly Generating Station are anticipated. The following sections discuss potential impacts on the Chassahowitzka and Okefenokee Class I areas.

9.2.1 IMPACTS ON SOILS

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

The potential impact of NO_x on soils is due primarily to acid precipitation, a secondary pollutant formed from the chemical conversion of nitrogen compounds under the influence of oxygen, water, and sunlight to form nitrous and nitric acids. The greatest potential impact to soils is increased acidification causing a lowering of soil pH with a concomitant decrease in the cation exchange capacity of the soil. The cation exchange capacity of the soil is also determined by soil texture, organic matter content, amount of clay present, etc. The soils at the refuge range from peat (up to 15 feet thick), black mucky fine sands overlying sandy clay loam, black clay loam over a clay subsoil, and light to dark gray sands. These soils are generally acid to strongly acid. The abundance of organics in upper horizons or abundance of clay in the soil profile suggests a cation exchange capacity capable of neutralizing any acid deposition from rainfall. Due to the low projected emissions of NO_x, no effects on rainwater pH will be measurable from this source and no discernible changes in soil chemistry will occur.

Another potential impact to soils is from trace-element or particulate emissions. Particulates may contain trace elements that can reach the soil through direct deposition, washing of plants by rainfall, and decomposition of plant litter. The ultimate concern is potential uptake by plants and subsequent consumption by animals. Included among the PM will be low concentrations of heavy metals. The expected maximum concentrations of PM_{10} and associated heavy metals are insignificant and will have no effect on soils in the refuge.

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

9.2.2 IMPACTS ON VEGETATION

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

The Okefenokee NWR comprises 396,000 acres of the 438,000-acre Okefenokee Swamp in southeastern Georgia, barely extending into Baker County, Florida. The elevations range from 103 to 128 feet above mean sea level. Within this nearly level terrain are lakes, islands, expansive cypress and deciduous hardwood swamps, pine flatwoods, upland hardwood forests, and vast areas of prairies (herbaceous wetlands or marshes). The swamp is the headwater to two major rivers, the St. Mary's and Suwanee Rivers.

The major communities on the Okefenokee NWR include cypress swamps, deciduous hardwood wetland and upland forests, pine forests dominated by or a combination of longleaf pine, slash pine, pond pine, and/or loblolly pine, and expansive areas of prairie including marshes. Lakes are common in the refuge. Potential impacts to vegetation from NO_x and PM_{10} have been evaluated with respect to dose response curves that have been developed for various plant species and their sensitivity to these pollutants. Plant damage can occur through either acute (short-term, high concentration) or chronic (long-term, relatively low concentration) exposure.

The literature was reviewed as to potential effects of air pollutants on vegetation. It was concluded that even the maximum impacts projected to occur in the immediate vicinity of the J.R. Kelly Generating Station due to operation of the new CTG would be below thresholds shown to cause damage to vegetation. Maximum air pollutant impacts at the Chassahowitzka and Okefenokee NWRs due to emissions from the repowering project CTG will be far less, as presented previously. The potential for damage at the Chassahowitzka and Okefenokee NWRs could, therefore, be considered negligible given the much lower air pollution impacts predicted at Chassahowitzka and Okefenokee NWRs relative to the immediate J.R. Kelly Generating Station plant vicinity and the absence of any plant species at Chassahowitzka and Okefenokee NWRs that would be especially sensitive to the very low predicted pollutant concentrations.

9.2.3 IMPACTS ON WILDLIFE

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

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

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

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

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

In conclusion, it is unlikely the projected air emission levels from the J.R. Kelly Generating Station Repowering Project will have any measurable direct or indirect effects on wildlife utilizing the Chassahowitzka and Okefenokee NWRs.

9.3 VISIBILITY IMPAIRMENT POTENTIAL

No visibility impairment at the local level is expected due to the types and quantities of emissions projected for the new CTG. Opacity of the CTG exhaust will be 10 percent or less, excluding water. Emissions of primary particulates and sulfur oxides from the CTG will be low due to the primary use of pipeline quality natural gas and low sulfur, low ash distillate fuel oil as the back-up fuel source. The new CTG will comply with all applicable FDEP requirements pertaining to visible emissions.

A Level 1 visibility screening analysis was conducted using the VISCREEN program, consistent with EPA (1988) guidance. Emissions input to the VISCREEN program were the maximum short-term (g/s) emission rates for primary PM, NO_x, and H_2SO_4 mist from the proposed CTG. These rates were 1.3 g/s of PM, 23.3 g/s of NO_x, and 0.83 g/s of H_2SO_4 mist. Tables 9-1 and 9-2 summarize the results of the Level 1 analysis for the Chassahowitzka or Okefenokee NWR Class I areas, respectively. The Level 1 visibility analysis, even with the conservative assumptions inherent to such an analysis, resulted in impact values well below the screening thresholds. Therefore, it is concluded that emissions from the repowering project CTG will not cause impairment of visibility in either the Chassahowitzka or Okefenokee NWR Class I areas.

Table 9-1. Visual Effects Screening Analysis-Chassahowitzka NWR

Visual Effects Screening Analysis for
Source: KELLY STATION REPOWERING PROJECT
Class I Area: CHASSAHOWITZKA NWR

*** Level-1 Screening ***

Input Emissions for

Particulates	1.30	G /S
NOx (as NO2)	23.30	G /S
Primary NO2	.00	G /S
Soot	.00	G /S
Primary SO4	.83	G /S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	65.00 km
Source-Observer Distance:	101.00 km
Min. Source-Class I Distance:	101.00 km
Max. Source-Class I Distance:	108.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	101.0	84.	2.00	.294	.05	-.000
SKY	140.	84.	101.0	84.	2.00	.145	.05	-.003
TERRAIN	10.	84.	101.0	84.	2.00	.092	.05	.001
TERRAIN	140.	84.	101.0	84.	2.00	.025	.05	.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	60.	92.4	109.	2.00	.313	.05	-.000
SKY	140.	60.	92.4	109.	2.00	.153	.05	-.004
TERRAIN	10.	35.	80.2	134.	2.00	.124	.05	.002
TERRAIN	140.	35.	80.2	134.	2.00	.035	.05	.002

Table 9-2. Visual Effects Screening Analysis-Okefenokee NWR

```
                Visual Effects Screening Analysis for
                  Source: KELLY STATION REPOWERING
                  Class I Area: OKEFENOKEE NWR

                  ***   Level-1 Screening   ***
Input Emissions for

   Particulates     1.30  G  /S
   NOx (as NO2)    23.30  G  /S
   Primary NO2       .00  G  /S
   Soot              .00  G  /S
   Primary SO4       .83  G  /S
    **** Default Particle Characteristics Assumed

              Transport Scenario Specifications:

    Background Ozone:                    .04 ppm
    Background Visual Range:           65.00 km
    Source-Observer Distance:         103.00 km
    Min. Source-Class I Distance:     103.00 km
    Max. Source-Class I Distance:     159.00 km
    Plume-Source-Observer Angle:       11.25 degrees
    Stability:   6
    Wind Speed:   1.00 m/s
```

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	84.	103.0	84.	2.00	.277	.05	-.000
SKY	140.	84.	103.0	84.	2.00	.137	.05	-.003
TERRAIN	10.	84.	103.0	84.	2.00	.086	.05	.001
TERRAIN	140.	84.	103.0	84.	2.00	.023	.05	.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E Crit	Delta E Plume	Contrast Crit	Contrast Plume
SKY	10.	60.	94.2	109.	2.00	.295	.05	-.000
SKY	140.	60.	94.2	109.	2.00	.144	.05	-.004
TERRAIN	10.	35.	81.8	134.	2.00	.115	.05	.002
TERRAIN	140.	35.	81.8	134.	2.00	.033	.05	.001

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ATTACHMENT A

APPLICATION FOR AIR PERMIT

TITLE V SOURCE

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: **City of Gainesville, Gainesville Regional Utilities (GRU)**	
2. Site Name: **J.R. Kelly Generating Station**	
3. Facility Identification Number: **0010005** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **605 SE 3rd Street** City: **Gainesville** County: **Alachua** Zip Code: **32601-7060**	
5. Relocatable Facility? [ ] Yes [✔] No	6. Existing Permitted Facility? [✔] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Yolanta Jonynas** **Senior Electric Utility Environmental Engineer**
2. Application Contact Mailing Address: Organization/Firm: **City of Gainesville, GRU** Street Address: **P.O. Box 147117 (A136)** City: **Gainesville** State: **FL** Zip Code: **32614-7117**
3. Application Contact Telephone Numbers: Telephone: **(352) 334-3400, Ext. 1284** Fax: **(352) 334-3151**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	Sept. 7, 1999
2. Permit Number:	0010005-002-AC
3. PSD Number (if applicable):	PSD-FL-276
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: **0010005-001-AV**

[ ] 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: **Michael L. Kurtz – General Manager**
2.	Application Contact Mailing Address: Organization/Firm: **City of Gainesville, GRU** Street Address: **P.O. Box 147117 (A134)** City: **Gainesville** State: **FL** Zip Code: **32614-7117**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(352) 334-2811** Fax: **(352) 334-2277**
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.* Michael L. Kurtz 9/3/99 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: **32606-5004**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 332-6230, Ext. 351** Fax: **(352) 332-6722**

4. Professional Engineer Statement:

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

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

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

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

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

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

Thomas W. Davis

Signature

Date 9/3/99

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
009	Combustion Turbine Unit CC-1	AC1A	$7,500

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations: **GRU is proposing a repowering project at the J.R. Kelly Generating Station, which will entail adding a new, General Electric (GE) 7EA combustion turbine generator (CTG) and heat recovery steam generator (HRSG) that will operate in conjunction with the existing Unit No. 8 steam turbine. The new CTG (Unit CC-1) will be capable of both simple- and combined-cycle modes of operation and will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a back-up fuel source. Unit CC-1 will operate at annual capacity factors up to 100 and 11.4 percent for natural gas and oil firing, respectively.**
2. Projected or Actual Date of Commencement of Construction: **February 2000**
3. Projected Date of Completion of Construction: **February 2001**

Application Comment

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **372.0**	North (km): **3,280.2**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS):		Longitude (DD/MM/SS):	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters):			

Facility Contact

1. Name and Title of Facility Contact: **Yolanta Jonynas, Senior Electric Utility Environmental Engineer**
2. Facility Contact Mailing Address: Organization/Firm: **City of Gainesville, GRU** Street Address: **P.O. Box 147117 (A136)** City: **Gainesville** State: **FL** Zip Code: **32614-7117**
3. Facility Contact Telephone Numbers: Telephone: **(352) 334-3400, Ext. 1284** Fax: **(352) 334-3151**

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

See 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**	
H106	**A**	**N/A**	**N/A**	**N/A**	**Hydrochloric Acid**
H107	**A**	**N/A**	**N/A**	**N/A**	**Hydrofluoric Acid**
HAPS	**A**	**N/A**	**N/A**	**N/A**	**Total HAPs**

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [ ] Attached, Document ID: **Fig. 2-1** [ ] Not Applicable [ ] Waiver Requested **(PSD Application)**
2. Facility Plot Plan: [ ] Attached, Document ID: **Fig. 2-2** [ ] Not Applicable [ ] Waiver Requested **(PSD Application)**
3. Process Flow Diagram(s): [ ] Attached, Document ID: **Fig. 2-3** [ ] Not Applicable [ ] Waiver Requested **(PSD Application)**
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: **PSD App.** [ ] Not Applicable
7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

Items 8. through 15. above previously submitted – see J.R. Kelly Generating Station Title V permit application.

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.

2. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Emission unit consists of one General Electric (GE) 7121 7EA combustion turbine generator (CTG). The CTG may operate in simple-cycle or combined-cycle modes of operation. The CTG will be fired primarily using pipeline quality natural gas with low-sulfur distillate fuel oil serving as a back-up fuel.

4. Emissions Unit Identification Number: [ ] No ID
ID: **009 (CC-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)
The proposed J.R. Kelly Generating Station Repowering Project consists of the addition of one, GE PG7121 (7EA) CTG and an HRSG together with continued use of the existing Unit No. 8 steam turbine. New Unit CC-1 will be capable of both simple- and combined-cycle modes of operation and will be fired primarily with pipeline-quality natural gas. Low-sulfur distillate fuel oil will serve as a supplemental, back-up fuel source.

In combined-cycle operating mode, Unit CC-1 will utilize an unfired HRSG to produce steam by recovering waste heat from the hot CTG exhaust gases. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine to generate additional electricity.

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 (natural gas-firing)
   Water injection (distillate fuel-oil firing)

2. Control Device or Method Code(s): **25 (dry low-NO$_x$), 28 (water injection)**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **General Electric** Model Number: **PG7121 (7EA)**
2. Generator Nameplate Rating: **83** MW **(nominal)**
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:	**1,120.5 (HHV)**	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 higher heating value (HHV) at 100 percent load, 20°F, fuel oil-firing operating conditions. Heat input will vary with load, fuel type, and ambient temperature.

New Unit CC-1 will operate at annual capacity factors up to 100 and 11.4 percent for natural gas and oil firing, respectively. At baseload operation, these annual capacity factors are equivalent to 8,760 and 1,000 hours per year (hr/yr) for natural gas and oil firing, respectively. Annual CTG operating hours for oil firing will increase with lower load operations. In lieu of an operating hour constraint for oil-firing, a permit condition limiting distillate fuel oil consumption to no more than 8,001,200 gallons per year is requested.

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? **CC-1, Bypass CC-1**	1. Emission Point Type Code: **3**

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

CC-1: Combined-cycle mode, HRSG outlet stack.
Bypass CC-1: Simple-cycle mode, HRSG bypass stack.

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

N/A

4. Discharge Type Code: **V**	6. Stack Height: **CC-1 100** feet; **Bypass CC-1 78** feet	7. Exit Diameter: **CC-1 15.5** feet; **Bypass CC-1 15.5** feet
8. Exit Temperature: **242 °F**	9. Actual Volumetric Flow Rate: **704,482** acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:

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

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

Stack temperature and flow rate are for combined-cycle, 100 percent load, 59°F, and natural gas-firing operating conditions. Stack temperature and flow rate will vary with operating mode, load, fuel type, and ambient temperature. See Tables 2-8 through 2-11 of the PSD permit application, dated September 1999.

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

Segment Description and Rate: Segment 1 of 2

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**	
4. Maximum Hourly Rate: **1.057**	5. Maximum Annual Rate: **9,259.3**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,052**

10. Segment Comment (limit to 200 characters):

Fuel heat content (Field 9) represents higher heating value (HHV).

Segment Description and Rate: Segment 2 of 2

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

Combustion turbine fired with distillate fuel oil.

2. Source Classification Code (SCC): **20100101**	3. SCC Units: **Thousand Gallons Burned**	
3. Maximum Hourly Rate: **8.001**	4. Maximum Annual Rate: **8,001.2**	6. Estimated Annual Activity Factor:
6. Maximum % Sulfur: **0.05**	7. Maximum % Ash: **0.01**	8. Million Btu per SCC Unit: **137**

9. Segment Comment (limit to 200 characters):

Fuel heat content (Field 9) represents higher heating value (HHV).

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 – VOC			**NS**
7 – H106			**NS**
8 – HAPS			**NS**

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: **166.0** lb/hour **207.2** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **166.0 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F, fuel oil-firing case (ISO conditions). Annual emissions based on 32.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 166.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/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: **9.0 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **32.0** 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).** **Limit applicable for natural gas-firing (ISO conditions).**	

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: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **166.0** 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).** **Limit applicable for distillate fuel oil-firing (ISO conditions).**	

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: **54.0** lb/hour **231.0** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **54.0 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F, natural gas-firing case (ISO conditions). Annual emissions based on 54.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 43.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
5. Requested Allowable Emissions and Units: **25 ppmvd**	4. Equivalent Allowable Emissions: **54.0** 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 for natural gas-firing (ISO conditions) during first year of operations.**	

<u>Allowable Emissions</u> Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
6. Requested Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **43.0** 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 for natural gas-firing (ISO conditions) following first year of operations.**	

<u>Allowable Emissions</u> Allowable Emissions 3 of 3

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
7. Requested Allowable Emissions and Units: **20 ppmvd**	4. Equivalent Allowable Emissions: **43.0** 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 for distillate fuel oil-firing (ISO conditions).**	

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: **10.0** lb/hour **24.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10.0 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F, fuel oil-firing case (ISO conditions). Annual emissions based on 5.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 10.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/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: **10% opacity**	4. Equivalent Allowable Emissions: **5.0** 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)** **Limit applicable for natural gas-firing (ISO conditions).**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
9. Requested Allowable Emissions and Units: **10 % opacity**	4. Equivalent Allowable Emissions: **10.0** 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)** **Limit applicable for distillate fuel oil-firing (ISO conditions).**	

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: **10.0** lb/hour **24.4** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10.0 lb/hr** Reference: **GE data**	7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F, fuel oil-firing case (ISO conditions). Annual emissions based on 5.0 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 10.0 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/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:
10. Requested Allowable Emissions and Units: **10% opacity**	4. Equivalent Allowable Emissions: **5.0** 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)** **Limit applicable for natural gas-firing (ISO conditions).**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
11. Requested Allowable Emissions and Units: **10 % opacity**	4. Equivalent Allowable Emissions: **10.0** 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)** **Limit applicable for distillate fuel oil-firing (ISO conditions).**	

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: **51.9** lb/hour **47.1** tons/year	4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **51.9 lb/hr** Reference: **GE data**	7. Emissions Method Code: **2**

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

(0.05 lb S/100 lb oil) x (51,851 lb oil/hr) x (2 lb SO_2/lb S) = 51.9 lb/hr SO_2

Annual emissions based on 5.5 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 51.9 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/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:
12. Requested Allowable Emissions and Units: **Pipeline-quality natural gas**	4. Equivalent Allowable Emissions: **5.5** lb/hour **N/A** tons/year

5. Method of Compliance (limit to 60 characters):
40 CFR Part 75 Appendix D procedures in lieu of NSPS 40 CFR 60, Subpart GG monitoring.

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 for natural gas-firing (ISO conditions).

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **Other**	2. Future Effective Date of Allowable Emissions:
13. Requested Allowable Emissions and Units: **0.05 weight % S**	4. Equivalent Allowable Emissions: **51.9** lb/hour **N/A** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis for sulfur content**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **FDEP Rule 62-212.400(5)(c), F.A.C. (BACT)** **Limit applicable for distillate fuel oil-firing (ISO conditions).**	

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: **4.5** lb/hour **9.2** tons/year		4. Synthetically Limited? [✔]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **4.5 lb/hr** Reference: **GE data**		7. Emissions Method Code: **5**
8. Calculation of Emissions (limit to 600 characters): **Hourly emission rate based on GE data for 100 percent load, 59°F, fuel oil-firing case (ISO conditions). Annual emissions based on 1.8 lb/hr (100 percent load, 59°F, natural gas-firing case) for 7,760 hrs/yr and 4.5 lb/hr (100 percent load, 59°F, distillate fuel oil-firing case) for 1,000 hrs/yr.**		
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:
14. 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):	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
15. 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 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	
5. Method of Compliance: **EPA Reference Method 9**	
6. Visible Emissions Comment (limit to 200 characters): **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	
7. Method of Compliance: **EPA Reference Method 9**	
8. Visible Emissions Comment (limit to 200 characters): **Excess emissions resulting from startup, shutdown, fuel switching, load changes, 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:
6. 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: **CO2**	2. Pollutant(s): **Carbon Dioxide**
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. 2-3 (PSD Application)** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [α] Attached, Document ID: Att. A-3 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: **Sect. 5.0 (PSD Application)** [ ] 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:_______________ [α] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [α] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [α] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application **See PSD application dated September 1999** [ ] Attached, Document ID:________ [ ] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [α] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [✔] Attached, Document ID: **Att. A-4** [ ] 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: **Att. A-5** [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable

ATTACHMENT A-1

REGULATORY APPLICABILITY ANALYSES

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

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)		CC-1	General recordkeeping and reporting requirements.
Performance Tests	§60.8		CC-1	Conduct performance tests as required by EPA or FDEP. **(potential future requirement)**
Compliance with Standards	§60.11(a) thru (d), and (f)		CC-1	General compliance requirements. Addresses requirements for visible emissions tests.
Circumvention	§60.12		CC-1	Cannot conceal an emission which would otherwise constitute a violation of an applicable standard.
Monitoring Requirements	§60.13(a), (b), (d), (e), and (h)		CC-1	Requirements pertaining to continuous monitoring systems.
General notification and reporting requirements	§60.19		CC-1	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)		CC-1	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.
Standards for Sulfur Dioxide	§60.333		CC-1	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.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 2 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart GG - Standard of Performance for Stationary Gas Turbines (continued)				
Monitoring Requirements	§60.334(a)		CC-1	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 CTGs using water injection for NO_x control.
Monitoring Requirements	§60.334(b)(2) and (c)		CC-1	Requires periodic monitoring of fuel sulfur and nitrogen content. Defines excess emissions
Test Methods and Procedures	§60.335		CC-1	Specifies monitoring procedures and test methods.
40 CFR Part 60 - Standards of Performance for New Stationary Sources: Subparts B, C, Ca, 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, PPP, QQQ, RRR, SSS, TTT, UUU, VVV, and WWW		X		None of the listed NSPS' contain requirements which are applicable to Kelly Station Unit CC-1.
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 Kelly Station Unit CC-1.
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, W, X, Y, CC, DD, EE, GG, II, JJ, KK, LL, OO, PP, QQ, RR, VV, EEE, GGG, III, and JJJ		X		None of the listed NESHAPS' contain requirements which are applicable to Kelly Station Unit CC-1.
40 CFR Part 72 - Acid Rain Program Permits				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 3 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart A - Acid Rain Program General Provisions				
Standard Requirements	§72.9 excluding §72.9(c)(3)(i), (ii), and (iii), and §72.9(d)		CC-1	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		CC-1	General requirements pertaining to the Designated Representative.
Subpart C - Acid Rain Application				
Requirements to Apply	§72.30(a), (b)(2)(ii), (c), and (d)		CC-1	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. 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		CC-1	Acid Rain Program permit shield for units filing a timely and complete application. Application is binding pending issuance of Acid Rain Permit.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 4 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart D - Acid Rain Compliance Plan and Compliance Options				
General	§72.40(a)(1)		CC-1	General SO_2 compliance plan requirements.
General	§72.40(a)(2)	X		General NO_x compliance plan requirements are not applicable to Kelly Station Unit CC-1.
Subpart E - Acid Rain Permit Contents				
Permit Shield	§72.51		CC-1	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)		CC-1	Procedures for fast-track modifications to Acid Rain Permits. **(potential future requirement)**
Subpart I - Compliance Certification				
Annual Compliance Certification Report	§72.90		CC-1	Requirement to submit an annual compliance report. **(future requirement)**
40 CFR Part 75 - Continuous Emission Monitoring				
Subpart A - General				
Prohibitions	§75.5		CC-1	General monitoring prohibitions.
Subpart B - Monitoring Provisions				
General Operating Requirements	§75.10		CC-1	General monitoring requirements.
Specific Provisions for Monitoring SO_2 Emissions	§75.11(d)(2)		CC-1	SO_2 continuous monitoring requirements for gas- and oil-fired units. Appendix D election will be made.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 5 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Specific Provisions for Monitoring NO_x Emissions	§75.12(a) and (b)		CC-1	NO_x continuous monitoring requirements for coal-fired units, gas-fired nonpeaking units, or oil-fired nonpeaking units
Specific Provisions for Monitoring CO_2 Emissions	§75.13(b)		CC-1	CO_2 continuous monitoring requirements. Appendix G election will be made.
Subpart B - Monitoring Provisions				
Specific Provisions for Monitoring Opacity	§75.14(d)		CC-1	Opacity continuous monitoring exemption for diesel-fired units.
Subpart C - Operation and Maintenance Requirements				
Certification and Recertification Procedures	§75.20(b)		CC-1	Recertification procedures **(potential future requirement)**
Certification and Recertification Procedures	§75.20(c)		CC-1	Recertification procedure requirements. **(potential future requirement)**
Quality Assurance and Quality Control Requirements	§75.21 except §75.21(b)		CC-1	General QA/QC requirements (excluding opacity).
Reference Test Methods	§75.22		CC-1	Specifies required test methods to be used for recertification testing **(potential future requirement)**.
Out-Of-Control Periods	§75.24 except §75.24(e)		CC-1	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)		CC-1	General missing data requirements.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 6 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Determination of Monitor Data Availability for Standard Missing Data Procedures	§75.32		CC-1	Monitor data availability procedure requirements.
Standard Missing Data Procedures	§75.33(a) and (c)		CC-1	Missing data substitution procedure requirements.
Subpart F - Recordkeeping Requirements				
General Recordkeeping Provisions	§75.50(a), (b), (d), and (e)(2)		CC-1	General recordkeeping requirements for NO_x and Appendix G CO_2 monitoring.
Monitoring Plan	§75.53(a), (b), (c), and (d)(1)		CC-1	Requirement to prepare and maintain a Monitoring Plan.
General Recordkeeping Provisions	§75.54(a), (b), (d), and (e)(2)		CC-1	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions for Specific Situations	§75.55(c)		CC-1	Specific recordkeeping requirements for Appendix D SO_2 monitoring.
General Recordkeeping Provisions	§75.56(a)(1), (3), (5), (6), and (7)		CC-1	Requirements pertaining to general recordkeeping.
General Recordkeeping Provisions	§75.56(b)(1)		CC-1	Requirements pertaining to general recordkeeping for Appendix D SO_2 monitoring.
Subpart G - Reporting Requirements				
General Provisions	§75.60		CC-1	General reporting requirements.
Notification of Certification and Recertification Test Dates	§75.61(a)(1) and (5), (b), and (c)		CC-1	Requires written submittal of recertification tests and revised test dates for CEMS. Notice of certification testing shall be submitted at least 45 days prior to the first day of recertification testing. Notification of any proposed adjustment to certification testing dates must be provided at least 7 business days prior to the proposed date change.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 7 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart G - Reporting Requirements				
Recertification Application	§75.63		CC-1	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)		CC-1	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		CC-1	Requirement to submit offset plans for excess SO_2 emissions not later than 60 days after the end of any calendar year during which an affected unit has excess SO_2 emissions. Required contents of offset plans are specified **(potential future requirement)**.
Deduction of Allowances to Offset Excess Emissions of Sulfur Dioxide	§77.5(b)		CC-1	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		CC-1	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				

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 8 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Production and Consumption Controls	Subpart A	X		Kelly Station Unit CC-1 will not produce or consume ozone depleting substances.
Servicing of Motor Vehicle Air Conditioners	Subpart B		Vehicle Fleet Maintenance	Servicing of motor vehicles which involves refrigerant in the motor vehicle air conditioner is conducted by City of Gainesville staff 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		The Kelly Station does not sell or distribute any banned nonessential substances.
The Labeling of Products Using Ozone-Depleting Substances	Subpart E	X		Kelly Station Unit CC-1 will not produce any products containing ozone depleting substances.
Subpart F - Recycling and Emissions Reduction				
Prohibitions	§82.154	X		Contractors maintain, service, repair, or dispose of any appliances in compliance with §82.154 prohibitions. Appliances are 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.
Required Practices	§82.156 except §82.156(i)(5), (6), (9), (10), and (11)	X		Contractors maintain, service, repair, and dispose of any appliances in compliance with §82.156 required practices.

Table A-1. Summary of Federally EPA Regulatory Applicability and Corresponding Requirements (Page 9 of 10)

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
Subpart F - Recycling and Emissions Reduction				
Required Practices	§82.156(i)(5), (6), (9), (10), and (11)		Appliances as defined by §82.152	Owner/operator requirements pertaining to repair of leaks.
Technician Certification	§82.161	X		Contractors' technicians meet the certification requirements.
Certification By Owners of Recovery and Recycling Equipment	§82.162	X		Contractors 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.

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

Regulation	Citation	Not Applicable	Applicable Emission Units	Applicable Requirement or Non-Applicability Rationale
40 CFR Part 64 - Compliance Assurance Monitoring		X		Program only applies to emission units which are equipped with control devices, excluding inherent process equipment.
40 CFR Part 70 - State Operating Permit Programs		X		State agency requirements - not applicable to individual emission sources.
40 CFR Parts 53, 54, 55, 56, 57, 58, 59, 67, 68, 69, 71, 74, 76, 79, 80, 81, 85, 86, 87, 88, 89, 90, 91, 92, 93, 95, and 96		X		The listed regulations do not contain any requirements which are applicable to Kelly Station Unit CC-1.

Source: ECT, 1999.

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 Kelly Station CC-1.
Modification of Permit Conditions	62-4.080, F.A.C	X			Application is for initial construction 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	62-4.200, 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) 39., (c), (d), and (e), F.A.C.***			CC-1	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.			CC-1	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 Kelly Station CC-1.
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 Kelly Station CC-1.
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.			CC-1	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 more than two hours in a 24 hour period are specifically requested for Kelly Station CC-1. 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 Kelly Station CC-1.

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(5), 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 Kelly Station CC-1.
New Source Review for Nonattainment Areas	62-212.500, F.A.C.	X			Kelly Station CC-1 is not located in a nonattainment area or a nonattainment area of influence.
Sulfur Storage and Handling Facilities	62-212.600, F.A.C.	X			Applicable only to sulfur storage and handling facilities.
Air Emissions Bubble	62-212.710, F.A.C.	X			Not applicable to Kelly Station CC-1.

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
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), and (4), 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.			CC-1	Optional provisions for Acid Rain permit revisions **(potential future requirement)**.
Trading of Emissions within a Source	62-213.415, F.A.C.	X			Applies only to facilities with a federally enforceable emissions cap.
Permit Applications	62-213.420(1)(a)2. and (1)(b), (2), (3), and (4), F.A.C.		X		Title V operating permit application required no later than 180 days after commencing operation. **(future requirement)**
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.

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 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(1), F.A.C.		X		Contains annual emissions fee form requirements.
Chapter 62-214—Requirements for Sources Subject to the Federal Acid Rain Program					
Purpose and Scope	§62-214.100, F.A.C.	X			Contains no applicable requirements.
Applicability	§62-214.300, F.A.C.		X		Kelly Station CC-1 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.			CC-1	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.

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
Acid Rain Compliance Plan and Compliance Options	§62-214.330(1)(a), F.A.C.			CC-1	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.			CC-1	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.			CC-1	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.			CC-1	Defines permit activation and termination procedures **(potential future requirement)**.
Chapter 62-242 - Motor Vehicle Standards and Test Procedures	62-242, F.A.C.	X			Not applicable to Kelly Station CC-1.
Chapter 62-243 - Tampering with Motor Vehicle Air Pollution Control Equipment	62-243, F.A.C.	X			Not applicable to Kelly Station CC-1.
Chapter 62-252 - Gasoline Vapor Control	62-252, F.A.C.	X			Not applicable to Kelly Station CC-1.
Chapter 62-256 - Open Burning and Frost Protection Fires					

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
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.***		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.***		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.***		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 Kelly Station CC-1.
Chapter 62-281 - Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling	62-281.300, .400, .500, and .900, F.A.C.			Vehicle Fleet Maintenance	Servicing of motor vehicle air conditioners and vehicle maintenance that may release refrigerants is conducted. Not applicable to Kelly Station CC-1.
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.

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
General Pollutant Emission Limiting Standard, Industrial, Commercial, and Municipal Open Burning Prohibited	**62-296.320(3), F.A.C.***		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			Kelly Station CC-1 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 Kelly Station CC-1.
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			Kelly Station CC-1 is not located in an ozone nonattainment area or an ozone air quality maintenance area.
Reasonably Available Control Technology (RACT) - Requirements for Major VOC- and NO_x-Emitting Facilities	62-296.570, F.A.C.	X			Kelly Station CC-1 is not located in a specified ozone nonattainment area or a specified ozone air quality maintenance area (i.e., is not located in Broward, Dade or Palm Beach Counties)
Reasonably Available Control Technology (RACT) - Lead	62-296.600 through 62-296.605, F.A.C.	X			Kelly Station CC-1 is not located in a lead nonattainment area or a lead 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)—Particulate Matter	§62-296.700 through 62-296.712, F.A.C.	X			Kelly Station CC-1 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.			CC-1	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 Kelly Station CC-1.
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.

*State requirement only; not federally enforceable.

Source: ECT, 1999.

ATTACHMENT A-2

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

Unconfined particulate matter emissions that may result from J.R. Kelly Generating Station operations include:

- Vehicular traffic on paved and unpaved roads.

- Periodic abrasive blasting.

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

- Chemical or water application to:

    - ❑ Unpaved roads
    - ❑ Unpaved yard areas

- Paving and maintenance of roads, parking areas and yards.

- Landscaping or planting of vegetation.

- Confining abrasive blasting where possible.

- Other techniques, as necessary

ATTACHMENT A-3

FUEL ANALYSES OR SPECIFICATIONS

Typical Natural Gas Composition

Component	Mole Percent (by volume)
<u>Gas Composition</u>	
Hexane+	0.0571
Propane	0.7101
I-butane	0.1479
N-butane	0.1558
I-Pentane	0.0476
N-Pentane	0.0308
Nitrogen	0.3750
Methane	94.7805
CO_2	0.5244
Ethane	3.1708
<u>Other Characteristics</u>	
Heat content (HHV)	1,051.9 Btu/ft^3 at 60°F, 14.73 psia, dry
Real specific gravity	0.5913
Sulfur content (maximum)	2.0 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: GRU, 1999.
FGT, 1999.

Typical No. 2 Fuel Oil Analysis

Parameter	Value
Minimum gross heating value, Btu/gal HHV	137,000
Ash, percent by weight (maximum)	0.05
Sulfur, percent by weight (maximum)	0.05
Fuel-bound nitrogen, percent by weight (maximum)	0.015

Note: Btu/gal = British thermal units per gallon.
HHV = higher heating value.

Source: GRU, 1999.

ATTACHMENT A-4

ALTERNATE METHODS OF OPERATION

Attachment A-4

Gainesville Regional Utilities – J.R. Kelly Generating Station
Unit CC-1: Alternate Methods of Operation

Method No.	Simple Cycle	Combined Cycle	Natural Gas Firing	Distillate Fuel Oil Firing	Operating Load Range (%)	Annual Operating Hours (Hrs/Yr)
1	X		X		60 - 100	8,760
2	X			X	60 - 100	1,000
3		X	X		60 – 100	8,760
4		X		X	60 - 100	1,000

Source: GRU, 1999.

ATTACHMENT A-5

ACID RAIN PART APPLICATION—PHASE II

Phase II Permit Application

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

This submission is: New ☐ ☒ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name	State	ORIS Code
J. R. Kelly	FL	664.

STEP 2 Enter the boiler ID# from NADB for each affected unit and indicate whether a *repowering plan* is being submitted for the unit by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a Boiler ID#	Compliance Plan b Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Compliance Plan c Repowering Plan	d New Units Commence Operation Date	e New Units Monitor Certification Deadline
~~JRK8~~ CC1 *	Yes	NO	1/29/2001	Unknown
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes for any unit

☐ For each unit that will be repowered, the Repowering Extension Plan form is included ~~and the~~ Repowering Technology Petition form has been submitted or will be submitted by June 1, 1997.

* Existing unit JRK8 will be repowered to a combined cycle unit via the addition of a combustion turbine and a heat recovery steam generator. The new unit will be designated as CC1 and will have a nominal capacity of 110 MW.

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

J. R. Kelly

Standard Requirements

Permit Requirements.

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

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

required under the Acid Rain Program; and,

Plant Name (from Step 1)

J. R. Kelly

Recordkeeping and Reporting Requirements (cont.)

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

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

Liability.

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

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

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

Name Randy L. Casserleigh

Signature	Date 1/29/95

STEP 5 (optional)
Enter the source AIRS and FINDS identification

AIRS	
FINDS	

United States
Environmental Protection Agency
Acid Rain Program

OMB No. 2060-0221
Expires 1-31-96

EPA

Certificate of Representation

Page 1

For more information, see instructions and refer to 40 CFR 72.24

This submission is: ☐ New ☒ Revised

This submission includes combustion or process sources under 40 CFR part 74 ☐

STEP 1
Identify the source by plant name, State, and, if applicable, ORIS code from NADB.

Plant Name	State	ORIS Code
J. R. KELLY (Generating Station)	FL	664

STEP 2
Enter requested Information for the Designated Representative.

Name MR. RANDY L. CASSERLEIGH	
Address Gainesville Regional Utilities P. O. Box 147117 (D38) Gainesville, FL 32614-7117	
Phone Number 352/334-2660 X 6240	Fax Number 352/334-2672

STEP 3
Enter requested information for the alternate designated representative, if applicable.

Name	
Address	
Phone Number	Fax Number

STEP 4
Complete Step 5, read the certifications, and sign and date. For a designated representative of a combustion or process source under 40 CFR part 74, the references in the certifications to "affected unit" or "affected units" also apply to the combustion or process source under 40 CFR part 74 and the references to "affected source" also apply to the source at which the combustion or process source is located.

I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the affected source and each affected unit at the source.

I certify that I have given notice of the agreement, selecting me as the designated representative or alternate designated representative, as applicable, for the affected source and each affected unit at the source identified in this certificate of representation, daily for a period of one week in a newspaper of general circulation in the area where the source is located or in a State publication designed to give general public notice.

I certify that I have all necessary authority to carry out my duties and responsibilities under the Acid Rain Program on behalf of the owners and operators of the affected source and of each affected unit at the source and that each such owner and operator shall be fully bound by my actions, inactions, or submissions.

I certify that I shall abide by any fiduciary responsibilities imposed by the agreement by which I was selected as designated representative or alternate designated representative, as applicable.

I certify that the owners and operators of the affected source and of each affected unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.

Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, an affected unit, or where a utility or industrial customer purchases power from an affected unit under life-of-the-unit, firm power contractual arrangements, I certify that:

> I have given a written notice of my selection as the designated representative or alternate designated representative, as applicable, and of the agreement by which I was selected to each owner and operator of the affected source and of each affected unit at the source; and
>
> Allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement or, if such multiple holders have expressly provided for a different distribution of allowances by contract, that allowances and the proceeds of transactions involving allowances will be deemed to be held or distributed in accordance with the contract.

Plant Name (from Step 1)	J. R. KELLY (Generating Station)

The agreement by which I was selected as the alternate designated representative, if applicable, includes a procedure for the owners and operators of the source and affected units at the source to authorize the alternate designated representative to act in lieu of the designated representative.

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

Signature (designated representative) [signature]	Date 7/10/97
Signature (alternate designated representative)	Date

STEP 5
Provide the name of every owner and operator of the source and each affected unit (or combustion or process source) at the source. Identify the units they own and/or operate by boiler ID# from NADB, if applicable. For owners only, identify each state or local utility regulatory authority with ratemaking jurisdiction over each owner, if applicable.

Name: City of Gainesville, Gainesville Regional Utilities					[X] Owner	[X] Operator
ID# JRK8	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities: Florida Public Service Commission (limited authority); City Commission of the City of Gainesville						

Name					[ ] Owner	[ ] Operator
ID#	ID#	ID#	ID#	ID#	ID#	ID#
ID#	ID#	ID#	ID#	ID#	ID#	ID#
Regulatory Authorities						

ATTACHMENT B

CTG EMISSIONS VENDOR DATA

Gainsville Regional Utility - Kelly Repowering

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	80%	60%
Ambient Temp.	Deg F.	20.	20.	20.
Output	kW	94,390.	75,510.	56,630.
Heat Rate (HHV)	Btu/kWh	11,470.	11,960.	13,540.
Heat Cons. (HHV) X 10^6	Btu/h	1,082.7	903.1	766.8
Auxiliary Power	kW	545	545	545
Output Net	kW	93,850.	74,970.	56,090.
Heat Rate (HHV) Net	Btu/kWh	11,540.	12,050.	13,670.
Exhaust Flow X 10^3	lb/h	2564.	2085.	1756.
Exhaust Temp.	Deg F.	974.	1004.	1055.
Exhaust Heat (HHV) X 10^6	Btu/h	719.8	610.6	543.1

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	36.	29.	25.
CO	ppmvd	25.	30.	29.
CO	lb/h	59.	57.	47.
UHC	ppmvw	7.	15.	15.
UHC	lb/h	10.	18.	14.
VOC	ppmvw	1.4	3.	3.
VOC	lb/h	2.	3.6	2.8
Particulates (TSP)	lb/h	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.91	0.90
Nitrogen	75.38	75.33	75.33
Oxygen	13.88	13.76	13.76
Carbon Dioxide	3.28	3.34	3.34
Water	6.57	6.67	6.68

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	12.0
Relative Humidity	%	100
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,761 @ 80 F (23,146 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/20/99 80008 permit perf gas 20.dat

Gainsville Regional Utility - Kelly Repowering

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	90%	80%	60%
Inlet Loss	in. H2O	3.5	3.5	3.5	3.5
Exhaust Loss	in. H2O	12.	12.	12.	12.
Ambient Temp.	Deg F.	59.	59.	59.	59.
Output	kW	83,290.	74,970.	66,640.	49,980.
Heat Rate (HHV)	Btu/kWh	11,730.	11,910.	12,390.	14,140.
Heat Cons. (HHV) X 10^6	Btu/h	977.	892.9	825.7	706.7
Auxiliary Power	kW	545	545	545	545
Output Net	kW	82,750.	74,430.	66,100.	49,440.
Heat Rate (HHV) Net	Btu/kWh	11,810.	12,000.	12,490.	14,290.
Exhaust Flow X 10^3	lb/h	2350.	2097.	1932.	1634.
Exhaust Temp.	Deg F.	1001.	1022.	1037.	1091.
Exhaust Heat (HHV) X 10^6	Btu/h	655.7	602.7	566.1	507.8

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.	9.
NOx AS NO2	lb/h	32.	29.	27.	23.
CO	ppmvd	25.	25.	25.	25.
CO	lb/h	54.	48.	44.	37.
UHC	ppmvw	7.	7.	9.	8.
UHC	lb/h	9.	8.	9.	7.
VOC	ppmvw	1.4	1.4	1.8	1.6
VOC	lb/h	1.8	1.6	1.8	1.4
Particulates (TSP)	lb/h	5.0	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.90	0.90	0.89	0.88
Nitrogen	74.91	74.87	74.87	74.86
Oxygen	13.87	13.73	13.74	13.71
Carbon Dioxide	3.22	3.28	3.28	3.30
Water	7.11	7.22	7.22	7.25

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Ambient Relative Humid.	%	60.0
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,761 @ 80 F (23,146 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/20/99 80008 permit perf gas iso.dat

BEST AVAILABLE COPY

Gainsville Regional Utility - Kelly Repowering
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	80%	60%
Ambient Temp.	Deg F.	95.	95.	95.
Output	kW	72,570.	58,050.	43,540.
Heat Rate (HHV)	Btu/kWh	12,150.	13,020.	14,840.
Heat Cons. (HHV) X 10^6	Btu/h	881.7	755.8	646.1
Auxiliary Power	kW	545	545	545
Output Net	kW	72,030.	57,510.	43,000.
Heat Rate (HHV) Net	Btu/kWh	12,240.	13,140.	15,030.
Exhaust Flow X 10^3	lb/h	2148.	1771.	1543.
Exhaust Temp.	Deg F.	1025.	1078.	1100.
Exhaust Heat (HHV) X 10^6	Btu/h	600.2	528.0	471.4

EMISSIONS

NOx	ppmvd @ 15% O2	9.	9.	9.
NOx AS NO2	lb/h	29.	25.	21.
CO	ppmvd	25.	25.	46.
CO	lb/h	49.	40.	63.
UHC	ppmvw	7.	7.	23.
UHC	lb/h	9.	7.	20.
VOC	ppmvw	1.4	1.4	4.6
VOC	lb/h	1.8	1.4	4.
Particulates (TSP)	lb/h	5.0	5.0	5.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.88	0.89
Nitrogen	73.62	73.55	73.61
Oxygen	13.64	13.43	13.61
Carbon Dioxide	3.16	3.26	3.17
Water	8.71	8.89	8.73

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	12.0
Relative Humidity	%	50
Fuel Type		Cust Gas
Fuel LHV	Btu/lb	20,761 @ 80 F (23,146 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/20/99 80008 permit perf gas 95.dat

Gainsville Regional Utility - Kelly Repowering

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	80%	60%
Ambient Temp.	Deg F.	20.	20.	20.
Output	kW	97,690.	78,150.	58,610.
Heat Rate (HHV)	Btu/kWh	11,470.	12,040.	13,560.
Heat Cons. (HHV) X 10^6	Btu/h	1,120.5	940.9	794.8
Auxiliary Power	kW	630	630	630
Output Net	kW	97,060.	77,520.	57,980.
Heat Rate (HHV) Net	Btu/kWh	11,540.	12,140.	13,710.
Exhaust Flow X 10^3	lb/h	2623.	2064.	1747.
Exhaust Temp.	Deg F.	968.	1041.	1086.
Exhaust Heat (HHV) X 10^6	Btu/h	694.5	597.6	531.2
Water Flow	lb/h	49,890.	39,980.	31,650.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	185.	154.	129.
CO	ppmvd	20.	20.	20.
CO	lb/h	47.	37.	32.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	10.	8.	7.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	5.	4.	3.5
Particulates (TSP)	lb/h	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.89	0.89	0.89
Nitrogen	73.85	73.71	73.88
Oxygen	13.17	12.75	12.86
Carbon Dioxide	4.61	4.87	4.83
Water	7.49	7.79	7.55

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	12.0
Relative Humidity	%	100
Fuel Type		Distillate, H/C Ratio 1.8
Fuel LHV	Btu/lb	18,300 @ 80 F (19,450 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/21/99 80008 permit perf dist 20.dat

BEST AVAILABLE COPY

Gainsville Regional Utility - Kelly Repowering

ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	90%	80%	60%
Ambient Temp.	Deg F.	59.	59.	59.	59.
Output	kW	86,200.	77,580.	68,960.	51,720.
Heat Rate (HHV)	Btu/kWh	11,700.	11,870.	12,390.	14,010.
Heat Cons. (HHV) X 10^6	Btu/h	1,008.5	920.9	854.4	724.6
Auxiliary Power	kW	630	630	630	630
Output Net	kW	85,570.	76,950.	68,330.	51,090.
Heat Rate (HHV) Net	Btu/kWh	11,790.	11,970.	12,500.	14,180.
Exhaust Flow X 10^3	lb/h	2400.	2105.	1934.	1649.
Exhaust Temp.	Deg F.	996.	1034.	1058.	1099.
Exhaust Heat (HHV) X 10^6	Btu/h	632.4	582.0	550.9	491.5
Water Flow	lb/h	42,750.	37,810.	34,030.	26,750.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.	42.
NOx AS NO2	lb/h	166.	151.	140.	118.
CO	ppmvd	20.	20.	20.	20.
CO	lb/h	43.	38.	35.	30.
UHC	ppmvw	7.	7.	7.	7.
UHC	lb/h	9.	8.	8.	6.
VOC	ppmvw	3.5	3.5	3.5	3.5
VOC	lb/h	4.5	4.	4.	3.
Particulates (TSP)	lb/h	10.0	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.88	0.88	0.88	0.88
Nitrogen	73.54	73.46	73.49	73.68
Oxygen	13.21	12.95	12.92	13.05
Carbon Dioxide	4.52	4.69	4.72	4.66
Water	7.85	8.03	8.00	7.73

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	12.0
Relative Humidity	%	60
Fuel Type		Distillate, H/C Ratio 1.8
Fuel LHV	Btu/lb	18,300 @ 80 F (19,450 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/21/99 80008 permit perf dist iso.dat

BEST AVAILABLE COPY

Gainsville Regional Utility - Kelly Repowering
ESTIMATED PERFORMANCE PG7121(EA)

Load Condition		BASE	80%	60%
Ambient Temp.	Deg F.	95.	95.	95.
Output	kW	74,740.	59,790.	44,850.
Heat Rate (HHV)	Btu/kWh	12,030.	12,850.	14,560.
Heat Cons. (HHV) X 10^6	Btu/h	899.1	768.3	653.
Auxiliary Power	kW	630	630	630
Output Net	kW	74,110.	59,160.	44,220.
Heat Rate (HHV) Net	Btu/kWh	12,130.	12,990.	14,770.
Exhaust Flow X 10^3	lb/h	2187.	1799.	1564.
Exhaust Temp.	Deg F.	1021.	1076.	1100.
Exhaust Heat (HHV) X 10^6	Btu/h	575.5	507.3	453.0
Water Flow	lb/h	32,690.	25,710.	19,550.

EMISSIONS

NOx	ppmvd @ 15% O2	42.	42.	42.
NOx AS NO2	lb/h	148.	126.	106.
CO	ppmvd	20.	20.	20.
CO	lb/h	39.	32.	28.
UHC	ppmvw	7.	7.	7.
UHC	lb/h	9.	7.	6.
VOC	ppmvw	3.5	3.5	3.5
VOC	lb/h	4.5	3.5	3.
Particulates (TSP)	lb/h	10.0	10.0	10.0

EXHAUST ANALYSIS % VOL.

Argon	0.87	0.86	0.88
Nitrogen	72.61	72.65	72.90
Oxygen	13.14	12.95	13.20
Carbon Dioxide	4.40	4.54	4.41
Water	8.98	9.00	8.61

SITE CONDITIONS

Elevation	ft.	145.0
Site Pressure	psia	14.62
Inlet Loss	in Water	3.5
Exhaust Loss	in Water	12.0
Relative Humidity	%	50
Fuel Type		Distillate, H/C Ratio 1.8
Fuel LHV	Btu/lb	18,300 @ 80 F (19,450 Btu/lb HHV)
Application		TEWAC Generator
Combustion System		9/42 DLN Combustor

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.

Output contingent upon generator water at adequate temperature, pressure, and flow

Distillate Fuel is Assumed to have 0.015% Fuel-Bound Nitrogen, or less.
FBN Amounts Greater Than 0.015% Will Add to the Reported NOx Value.

IPS- 80008 version code- 1 . 5 . 0 Opt: 11 71210696
NORTHRI 4/21/99 80008 permit perf dist 95.dat

ATTACHMENT C

CONTROL SYSTEM VENDOR QUOTE

ENGELHARD

101 WOOD AVENUE
ISELIN, NJ 08830
732-205-5000

POWER GENERATION SALES:
ENGELHARD CORPORATION
2205 CHEQUERS COURT
BEL AIR, MD 21015
PHONE 410-569-0297
FAX 410-569-1841
E-Mail Fred_Booth@ENGELHARD.COM

DATE:	**June 25, 1999**	**NO. PAGES**	**4**	**(INCLUDING COVER)**
TO:	**ECT** **ATTN: Tom Davis** **ENGELHARD** **ATTN: Nancy Ellison**	**via e-mail**		
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**		

RE: **ECT 990100-0100-1100**
City of Gainesville Combined Cycle Project
Camet® CO and NOxCAT™ VNX™ SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99483

Dear Mr. Davis,

We provide Engelhard Budgetary Proposal EPB99483 for Engelhard **Camet®** CO and **NOxCAT™ VNX™** vanadia-titania SCR Catalyst systems. This is per your e-mail request of June 24, 1999.

Our Proposal is based on:

- CO Catalyst for 90% CO reduction;
- SCR Catalyst for NOx reduction from 9 ppmvd @ 15% O_2 to 3.5 ppmvd @ 15% O_2 with ammonia slip of 5 ppmvd @ 15% O_2;
- Assumed HRSG inside liner dimensions of 55 ft. H x 22 ft. W;
- Assumed 28% aqueous ammonia to ammonia skid;
- Scope as noted: Typical to HRSG supplier

We request the opportunity to work with you on this project.

Sincerely yours,

ENGELHARD CORPORATION

Frederick A. Booth
Senior Sales Engineer

cc: Nancy Ellison - Proposal Administrator

ENGELHARD

ECT 990100-0100-1100
City of Gainesville Combined Cycle Project
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99483
June 25, 1999

ENGELHARD CORPORATION
CAMET® CO CATALYST SYSTEM
NOxCAT™ VNX™ SCR NOx ABATEMENT CATALYST SYSTEM

Engelhard Corporation ("Engelhard") offers to supply to Buyer the **Camet®** metal substrate CO System and **NOxCAT™ VNX™** ceramic substrate SCR systems summarized per the technical data and site conditions provided.

Scope of Supply
1. Engelhard **Camet®** CO catalyst in modules with internal support frame;
2. Engelhard **NOxCAT™ VNX™** SCR catalyst in modules with internal support frame;
3. Ammonia Delivery System Components - 28% aqueous ammonia to skid

BUDGET PRICES: **Per Turbine** **See Schedule**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	One year of operation* or 1.5 years after catalyst delivery, whichever occurs first.
Performance Guarantee:	Three (3) Years of operation* or 3.5 years after catalyst delivery, whichever occurs first. Catalyst warranty is prorated over the guaranteed life.
Expected Life	5 - 7 years

SCR SYSTEM DESIGN BASIS:

Gas Flow from:	GE 7EA Combustion Turbine
Gas Flow:	Horizontal
Fuel:	Natural Gas
Gas Flow Rate (At catalyst face):	See Performance data - Designed for Gas Velocities within ±15% at the reactor inlet
Temperature (At catalyst face):	Designed for Gas Temperature with maximum range ±20°F at the reactor inlet
CO Inlet (At catalyst face):	See Performance Data
CO Reduction	90% from Inlet levels
NOx Inlet (At catalyst face):	See Performance Data
NOx Reduction :	To 3.5 ppmvd @ 15% O_2
NH_3 Slip:	5 ppmvd @ 15%O_2
HRSG Cross Section	55 ft. H x 22 ft. W

ENGELHARD

ECT 990100-0100-1100
City of Gainesville Combined Cycle Project
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99483
June 25, 1999

Performance Data

GIVEN / CALCULATED DATA LOAD, %	100	80	80
TURBINE EXHAUST FLOW, lb/hr	2,350,008	1,932,012	1,634,004
TURBINE EXHAUST GAS ANALYSIS, % VOL. N2	74.90	74.87	74.86
O2	13.87	13.74	13.71
CO2	3.22	3.28	3.30
H2O	7.11	7.22	7.25
Ar	0.90	0.89	0.88
GIVEN: TURBINE CO, ppmvd @ 15% O2	24.7	24.2	24.1
CALC.: TURBINE CO, lb/hr	53.6	44.0	37.2
GIVEN: TURBINE NOx, ppmvd @ 15% O2	9	9	9
CALC.: TURBINE NOx, lb/hr	32.1	26.9	22.9
CALC. GAS MOL. WT.	28.48	28.48	28.47
FLUE GAS TEMP. @ CO and SCR CATALYST, F (+/-20)	650	650	650
DESIGN REQUIREMENTS			
CO CATALYST CO OUT, ppmvd @ 15% O2	2.5	2.5	2.5
SCR CATALYST NOx OUT, ppmvd @ 15% O2	3.5	3.5	3.5
NH3 SLIP, ppmvd @ 15% O2	5	5	5
FIT HRSG INSIDE LINER - 55 ft H x 22 ft W			
GUARANTEED PERFORMANCE DATA			
CO CATALYST CO CONVERSION, % - Min.	89.9%	89.7%	89.6%
CO OUT, lb/hr - Max.	5.4	4.5	3.9
CO OUT, ppmvd @ 15% O2 - Max.	2.5	2.5	2.5
CO PRESSURE DROP, "WG - Max.	1.0		
SCR CATALYST NOx CONVERSION, % - Min.	61.1%	61.1%	61.1%
NOx OUT, ppmvd @ 15% O2 - Max.	3.5	3.5	3.5
EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr	49.4	41.4	35.2
NH3 SLIP, ppmvd @ 15% O2 - Max.	5	5	5
SCR PRESSURE DROP, "WG - Max.	1.5		
CO SYSTEM	**$680,000**		
REPLACEMENT CO CATALYST MODULES	**$600,000**		
SCR SYSTEM	**$710,000**		
REPLACEMENT SCR CATALYST MODULES	**$350,000**		

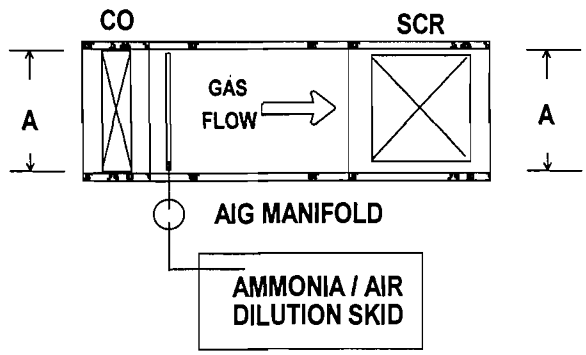
ENGELHARD

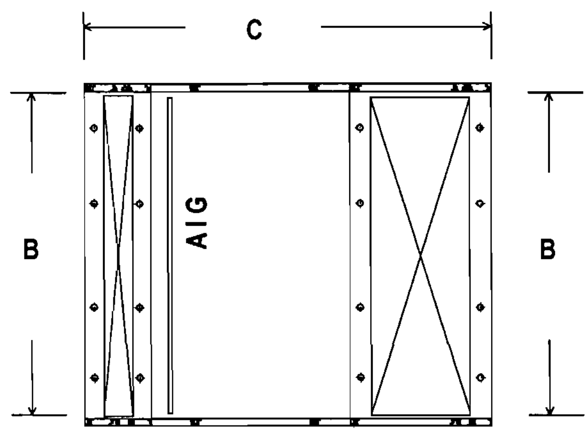
ECT 990100-0100-1100
City of Gainesville Combined Cycle Project
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB99483
June 25, 1999

Scope of Supply: The equipment supplied is installed by others in accordance with Engelhard design and installation instructions.
Engelhard **Camet®** CO and **NOxCAT™ VNX™** SCR catalyst in modules;
Internal support frames for catalyst modules - installed inside internally insulated casing (casing by others);
Ammonia Delivery System Components: Aqueous (28% Sol.) Ammonia to skid
- Ammonia Injection Grid (AIG);
- AIG manifold with flow control valves ;
- NH_3/Air dilution skid: Pre-piped & wired (including all valves and fittings)
  - Two (2) dilution air fans, one for back-up purposes
  - Panel mounted system controls for:
  - Blowers (on/off/flow indicators) System pressure indicators
  - Air/ammonia flow indicator and controller Main power disconnect switch

Assumed Dimensions:
Reactor Cross Section

Inside Liner Width	**(A)**	**22 ft**
Inside Liner Height	**(B)**	**55 ft**
Reactor Depth - CO and SCR	**(C)**	**15'-0"**





Excluded from Scope of Supply:
Ammonia storage and pumping
Internally insulated reactor Housing (HRSG Casing)
Any transitions to and from reactor
Any interconnecting field piping or wiring
Electrical grounding equipment
Utilities
Foundations
All Monitors
All other items not specifically listed in Scope of Supply

ATTACHMENT D

EMISSION RATE CALCULATIONS

Table 1. GRU J.R. Kelley Generating Station Repowering Project CC-1 Operating Scenarios - General Electric PG7121(EA)

Case	Ambient Temperature (oF)	Load (%)	CC-1 Combined Cycle	CC-1 Simple Cycle	Natural Gas Firing	Fuel Oil Firing
1	20	100	X	X	X	X
2	20	80	X	X	X	X
3	20	60	X	X	X	X
4	59	100	X	X	X	X
5	59	80	X	X	X	X
6	59	60	X	X	X	X
7	95	100	X	X	X	X
8	95	80	X	X	X	X
9	95	60	X	X	X	X

Sources: GRU, 1999.
ECT, 1999.

Table 2A. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Hourly Emission Rates - General Electric PG7121(EA) CTG
Natural Gas-Firing; First Year Operations

Temp. (°F)	Case	Load (%)	PM/PM10[1] (lb/hr)	PM/PM10[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	5.0	0.63	6.0	0.76	0.694	0.0874	0.0004	0.00005
	2	80	5.0	0.63	5.0	0.63	0.579	0.0729	0.0003	0.00004
	3	60	5.0	0.63	4.3	0.54	0.491	0.0619	0.0003	0.00004
59	4	100	5.0	0.63	5.5	0.69	0.626	0.0789	0.0004	0.00005
	5	80	5.0	0.63	4.6	0.58	0.529	0.0667	0.0003	0.00004
	6	60	5.0	0.63	3.9	0.50	0.453	0.0571	0.0003	0.00003
95	7	100	5.0	0.63	4.9	0.62	0.565	0.0712	0.0003	0.00004
	8	80	5.0	0.63	4.2	0.53	0.484	0.0610	0.0003	0.00004
	9	60	5.0	0.63	3.6	0.45	0.414	0.0522	0.0002	0.00003
		Maximums	**5.0**	**0.63**	**6.0**	**0.76**	**0.694**	**0.0874**	**0.0004**	**0.00005**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
20	1	100	9.0	36.0	4.54	24.4	59.0	7.43	1.5	2.0	0.25
	2	80	9.0	29.0	3.65	28.7	57.0	7.18	3.1	3.6	0.45
	3	60	9.0	25.0	3.15	27.8	47.0	5.92	3.1	2.8	0.35
59	4	100	9.0	32.0	4.03	24.7	54.0	6.80	1.5	1.8	0.23
	5	80	9.0	27.0	3.40	24.2	44.0	5.54	1.9	1.8	0.23
	6	60	9.0	23.0	2.90	24.1	37.0	4.66	1.7	1.4	0.18
95	7	100	9.0	29.0	3.65	24.8	49.0	6.17	1.5	1.8	0.23
	8	80	9.0	25.0	3.15	23.9	40.0	5.04	1.5	1.4	0.18
	9	60	9.0	21.0	2.65	45.3	63.0	7.94	5.0	4.0	0.50
		Maximums	**9.0**	**36.0**	**4.54**	**45.3**	**63.0**	**7.94**	**5.0**	**4.0**	**0.50**

[1] As measured by EPA Reference Method 5B or 17.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] EPA Electric Utility Hazardous Air Pollutant Study, Draft Report, Table C-1.3, June 1995.
[5] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 2B. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Hourly Emission Rates - General Electric PG7121(EA) CTG
Natural Gas-Firing; Following First Year of Operations

Temp. (°F)	Case	Load (%)	PM/PM10[1] (lb/hr)	PM/PM10[1] (g/sec)	SO_2[2] (lb/hr)	SO_2[2] (g/sec)	H_2SO_4[3] (lb/hr)	H_2SO_4[3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	5.0	0.63	6.0	0.76	0.694	0.0874	0.0004	0.00005
	2	80	5.0	0.63	5.0	0.63	0.579	0.0729	0.0003	0.00004
	3	60	5.0	0.63	4.3	0.54	0.491	0.0619	0.0003	0.00004
59	4	100	5.0	0.63	5.5	0.69	0.626	0.0789	0.0004	0.00005
	5	80	5.0	0.63	4.6	0.58	0.529	0.0667	0.0003	0.00004
	6	60	5.0	0.63	3.9	0.50	0.453	0.0571	0.0003	0.00003
95	7	100	5.0	0.63	4.9	0.62	0.565	0.0712	0.0003	0.00004
	8	80	5.0	0.63	4.2	0.53	0.484	0.0610	0.0003	0.00004
	9	60	5.0	0.63	3.6	0.45	0.414	0.0522	0.0002	0.00003
		Maximums	**5.0**	**0.63**	**6.0**	**0.76**	**0.694**	**0.0874**	**0.0004**	**0.00005**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
20	1	100	9.0	36.0	4.54	19.5	47.2	5.95	1.5	2.0	0.25
	2	80	9.0	29.0	3.65	28.7	57.0	7.18	3.1	3.6	0.45
	3	60	9.0	25.0	3.15	27.8	47.0	5.92	3.1	2.8	0.35
59	4	100	9.0	32.0	4.03	19.8	43.2	5.44	1.5	1.8	0.23
	5	80	9.0	27.0	3.40	24.2	44.0	5.54	1.9	1.8	0.23
	6	60	9.0	23.0	2.90	24.1	37.0	4.66	1.7	1.4	0.18
95	7	100	9.0	29.0	3.65	19.9	39.2	4.94	1.5	1.8	0.23
	8	80	9.0	25.0	3.15	23.9	40.0	5.04	1.5	1.4	0.18
	9	60	9.0	21.0	2.65	45.3	63.0	7.94	5.0	4.0	0.50
		Maximums	**9.0**	**36.0**	**4.54**	**45.3**	**63.0**	**7.94**	**5.0**	**4.0**	**0.50**

[1] As measured by EPA Reference Method 5B or 17.
[2] Based on natural gas sulfur content of 2.0 gr/100 ft^3.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] EPA Electric Utility Hazardous Air Pollutant Study, Draft Report, Table C-1.3, June 1995.
[5] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 3. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Hourly Emission Rates - General Electric PG7121(EA) CTG
Distillate Fuel Oil-Firing

Temp. (°F)	Case	Load (%)	PM/PM_{10} [1] (lb/hr)	PM/PM_{10} [1] (g/sec)	SO_2 [2] (lb/hr)	SO_2 [2] (g/sec)	H_2SO_4 [3] (lb/hr)	H_2SO_4 [3] (g/sec)	Lead[4] (lb/hr)	Lead[4] (g/sec)
20	1	100	10.0	1.26	57.6	7.26	6.62	0.8336	0.065	0.0082
	2	80	10.0	1.26	48.4	6.10	5.56	0.7000	0.055	0.0069
	3	60	10.0	1.26	40.9	5.15	4.69	0.5913	0.046	0.0058
59	4	100	10.0	1.26	51.9	6.53	5.95	0.7503	0.058	0.0074
	5	80	10.0	1.26	43.9	5.53	5.04	0.6357	0.050	0.0062
	6	60	10.0	1.26	37.3	4.69	4.28	0.5391	0.042	0.0053
95	7	100	10.0	1.26	46.2	5.82	5.31	0.6689	0.052	0.0066
	8	80	10.0	1.26	39.5	4.98	4.54	0.5716	0.045	0.0056
	9	60	10.0	1.26	33.6	4.23	3.86	0.4858	0.038	0.0048
		Maximums	**10.0**	**1.26**	**57.6**	**7.26**	**6.62**	**0.8336**	**0.065**	**0.0082**

Temp. (°F)	Case	Load (%)	NO_x (ppmvd)[5]	NO_x (lb/hr)	NO_x (g/sec)	CO (ppmvd)[5]	CO (lb/hr)	CO (g/sec)	VOC (ppmvd)[5]	VOC (lb/hr)	VOC (g/sec)
20	1	100	42.0	185.0	23.31	17.7	47.0	5.92	3.3	5.0	0.63
	2	80	42.0	154.0	19.40	16.7	37.0	4.66	3.2	4.0	0.50
	3	60	42.0	129.0	16.25	16.9	32.0	4.03	3.2	3.5	0.44
59	4	100	42.0	166.0	20.92	18.0	43.0	5.42	3.4	4.5	0.57
	5	80	42.0	140.0	17.64	17.2	35.0	4.41	3.3	4.0	0.50
	6	60	42.0	118.0	14.87	17.5	30.0	3.78	3.3	3.0	0.38
95	7	100	42.0	148.0	18.65	18.3	39.0	4.91	3.5	4.5	0.57
	8	80	42.0	126.0	15.88	17.7	32.0	4.03	3.4	3.5	0.44
	9	60	42.0	106.0	13.36	18.3	28.0	3.53	3.5	3.0	0.38
		Maximums	**42.0**	**185.0**	**23.31**	**18.3**	**47.0**	**5.92**	**3.5**	**5.0**	**0.63**

[1] As measured by EPA Reference Method 5B or 17.
[2] Based on fuel oil sulfur content of 0.05 wt percent.
[3] Based on 7.5% conversion of SO_2 to H_2SO_4.
[4] EPA AP-42 Emission Factor, Table 3.1-4., October 1996.
[5] Corrected to 15% O_2.

Sources: ECT, 1999.
GE, 1999.

Table 4. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Hourly Emission Rates - General Electric PG7121(EA)
Natural Gas-Firing: Noncriteria Pollutants

Maximum Hourly Heat Input: (Case 1)	1,083	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	977	10^6 Btu/hr
Maximum Annual Hours:	8,760	hrs/yr

Pollutant	Emission Factor ($lb/10^6$ Btu)	Emission Factor Reference	Emission Rates (lb/hr)	Emission Rates (ton/yr)
Arsenic	1.40E-07	2	1.52E-04	5.99E-04
Benzene	1.40E-06	1	1.52E-03	5.99E-03
Cadmium	4.40E-08	2	4.76E-05	1.88E-04
Chromium VI	9.60E-07	2	1.04E-03	4.11E-03
Cobalt	1.20E-07	2	1.30E-04	5.14E-04
Dioxins/Furans	1.20E-12	3	1.30E-09	5.14E-09
Formaldehyde	2.90E-05	1	3.14E-02	1.24E-01
Lead	3.70E-07	2	4.01E-04	1.58E-03
Manganese	3.00E-07	2	3.25E-04	1.28E-03
Mercury	7.80E-10	4	8.45E-07	3.34E-06
Naphthalene	6.70E-07	1	7.25E-04	2.87E-03
Nickel	2.30E-06	2	2.49E-03	9.84E-03
Phosphorus	2.20E-06	2	2.38E-03	9.41E-03
Polycyclic Organic Matter	5.00E-08	1	5.41E-05	2.14E-04
Toluene	1.02E-05	1	1.10E-02	4.36E-02
		Totals	**0.05**	**0.20**

Emission Factor References:
1 - EPA Electric Utility Hazardous Air Pollutant Study, Final Report, Table A-6, February 1998.
2 - EPA Electric Utility Hazardous Air Pollutant Study, Draft Report, Table C-1.3, June 1995.
3 - EPRI Synthesis Report, November 1994.
4 - Florida Coordinating Group (FCG), 1995.

Source: ECT, 1999.

Table 5. GRU J.R. Kelley Generating Station Repowering Project CC-1 Hourly Emission Rates - General Electric PG7121(EA) Distillate Fuel Oil-Firing: Noncriteria Pollutants

Maximum Hourly Heat Input: (Case 1)	1,121	10^6 Btu/hr
Average Hourly Heat Input: (Case 4)	1,009	10^6 Btu/hr
Maximum Annual Hours:	1,000	hrs/yr

Pollutant	Emission Factor ($lb/10^6$ Btu)	Emission Factor Reference	Emission Rates (lb/hr)	Emission Rates (ton/yr)
Acetaldehyde	8.20E-06	1	9.19E-03	4.13E-03
Antimony	2.20E-05	3	2.47E-02	1.11E-02
Arsenic	4.90E-06	3	5.49E-03	2.47E-03
Benzene	1.40E-06	1	1.57E-03	7.06E-04
Beryllium	3.30E-07	3	3.70E-04	1.66E-04
Cadmium	4.20E-06	3	4.71E-03	2.12E-03
Chromium	4.70E-05	3	5.27E-02	2.37E-02
Cobalt	9.10E-06	3	1.02E-02	4.59E-03
Dioxins/Furans	8.79E-10	1	9.85E-07	4.43E-07
Ethylbenzene	4.90E-07	1	5.49E-04	2.47E-04
Formaldehyde	3.00E-05	1	3.36E-02	1.51E-02
Hydrogen Chloride	2.30E-03	2	2.58E+00	1.16E+00
Hydrogen Fluoride	1.40E-04	2	1.57E-01	7.06E-02
Lead	5.80E-05	3	6.50E-02	2.92E-02
Manganese	3.40E-04	3	3.81E-01	1.71E-01
Methyl Chloroform	7.60E-06	1	8.52E-03	3.83E-03
Methylene Chloride	3.23E-05	1	3.61E-02	1.63E-02
Mercury	9.10E-07	3	1.02E-03	4.59E-04
Naphthalene	3.40E-07	1	3.81E-04	1.71E-04
Nickel	4.10E-04	2	4.59E-01	2.07E-01
Phenol	2.43E-05	1	2.72E-02	1.23E-02
Phosphorus	3.00E-04	3	3.36E-01	1.51E-01
Polycyclic Organic Matter	6.74E-07	1	7.55E-04	3.40E-04
Selenium	5.30E-06	3	5.94E-03	2.67E-03
Tetrachloroethylene	5.50E-07	1	6.16E-04	2.77E-04
Toluene	8.00E-06	1	8.96E-03	4.03E-03
Vinyl Acetate	5.15E-06	1	5.77E-03	2.60E-03
Xylenes	2.19E-06	1	2.45E-03	1.10E-03
		Totals	**4.2**	**1.9**

Emission Factor References:
1 - EPA Electric Utility Hazardous Air Pollutant Study, Final Report, Table A-5, February 1998.
2 - EPA Electric Utility Hazardous Air Pollutant Study, Draft Report, Table C-1.2, June 1995.
3 - EPA AP-42 Emission Factors, Table 3.1-4., October 1996.

Source: ECT, 1999.

Table 6.A. GRU J.R. Kelley Generating Station Repowering Project CC-1 Annual Emission Rates; First Year of Operations

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CC-1	4 - NG	7,760	32.0	124.2	54.0	209.5	1.80	6.98
CC-1	4 - Oil	1,000	166.0	83.0	43.0	21.5	4.50	2.25
		Totals	**N/A**	**207.2**	**N/A**	**231.0**	**N/A**	**9.23**

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			PM/PM_{10}		SO_2		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CC-1	4 - NG	7,760	5.0	19.4	5.5	21.1	0.0004	0.001
CC-1	4 - Oil	1,000	10.0	5.0	51.9	25.9	0.0585	0.029
		Totals	**N/A**	**24.4**	**N/A**	**47.1**	**N/A**	**0.031**

1. CC-1 operating with natural gas-firing at a 88.6% capacity factor; 7,760 hours/year at base load (Case 4).
2. CC-1 operating with fuel oil-firing at a 11.4% capacity factor; 1,000 hours/year at base load (Case 4).
3. SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft3.
4. SO_2 rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
GRU, 1999.

Table 6.B. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Annual Emission Rates; Following First Year of Operations

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			NO_x		CO		VOC	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CC-1	4 - NG	7,760	32.0	124.2	43.2	167.6	1.80	6.98
CC-1	4 - Oil	1,000	166.0	83.0	43.0	21.5	4.50	2.25
		Totals	**N/A**	**207.2**	**N/A**	**189.1**	**N/A**	**9.23**

Source	Case	Annual Operations (hrs/yr)	Emission Rates					
			PM/PM_{10}		SO_2		Lead	
			(lb/hr)	(tpy)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
CC-1	4 - NG	7,760	5.0	19.4	5.5	21.1	0.0004	0.001
CC-1	4 - Oil	1,000	10.0	5.0	51.9	25.9	0.0585	0.029
		Totals	**N/A**	**24.4**	**N/A**	**47.1**	**N/A**	**0.031**

1. CC-1 operating with natural gas-firing at a 88.6% capacity factor; 7,760 hours/year at base load (Case 4).
2. CC-1 operating with fuel oil-firing at a 11.4% capacity factor; 1,000 hours/year at base load (Case 4).
3. SO_2 rates based on natural gas sulfur content of 2.0 gr/100 ft3.
4. SO_2 rates based on fuel oil sulfur content of 0.05 wt. percent.

Sources: GE, 1999.
ECT, 1999.
GRU, 1999.

Table 7. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Annual Emission Rates
Noncriteria Air Pollutants

Pollutant	CAS No.	Emission Rates (lb/hr)	Emission Rates (ton/yr)
Acetaldehyde	75-07-0	9.19E-03	4.13E-03
Antimony	7440-36-0	2.47E-02	1.11E-02
Arsenic	7440-38-2	5.64E-03	3.07E-03
Benzene	71-43-2	3.08E-03	6.70E-03
Beryllium	7440-41-7	3.70E-04	1.66E-04
Cadmium	7440-43-9	4.75E-03	2.31E-03
Chromium	740-47-3	5.37E-02	2.78E-02
Cobalt	7440-48-4	1.03E-02	5.10E-03
Dioxins/Furans	1746-01-6	9.86E-07	4.48E-07
Ethylbenzene	100-41-4	5.49E-04	2.47E-04
Formaldehyde	50-00-0	6.50E-02	1.39E-01
Hydrogen Chloride	7647-01-0	2.58E+00	1.16E+00
Hydrogen Fluoride	7664-39-3	1.57E-01	7.06E-02
Lead	7439-92-1	6.54E-02	3.08E-02
Manganese	7439-96-5	3.81E-01	1.73E-01
Methyl Chloroform	71-5-56	8.52E-03	3.83E-03
Methylene Chloride	75-09-2	3.61E-02	1.63E-02
Mercury	7439-97-6	1.02E-03	4.62E-04
Naphthalene	91-20-3	1.11E-03	3.04E-03
Nickel	7440-02-0	4.62E-01	2.17E-01
Phenol	108-95-2	2.72E-02	1.23E-02
Phosphorus	7723-14-0	3.39E-01	1.61E-01
Polycyclic Organic Matter	N/A	8.09E-04	5.54E-04
Selenium	7782-49-2	5.94E-03	2.67E-03
Sulfuric Acid Mist	7664-93-9	6.58E+00	5.41E+00
Tetrachloroethylene	127-18-4	6.16E-04	2.77E-04
Toluene	108-88-3	2.00E-02	4.77E-02
Vinyl Acetate	108-05-4	5.77E-03	2.60E-03
Xylenes	1330-20-7	2.45E-03	1.10E-03
	Totals	**10.8**	**7.5**

Source: ECT, 1999.

Table 8. GRU J.R. Kelley Generating Station Repowering Projec
CC-1 General Electric PG7121(EA) CTG
NSPS GG NO_x Limits

Fuel	PG7121(EA) Gas Turbine ISO Heat Rate (LHV) (Btu/kw-hr)	PG7121(EA) Gas Turbine ISO Heat Rate (LHV) (kj/w-hr)	FBN F	NO_x Std (ppmvd)
Gas	10,521	11.101	0.0	97.3
Distillate	11,008	11.614	0.0	93.0

Sources: ECT, 1999.
GE, 1999.

Table 9.A. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Simple-Cycle

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
		100 % Load			80 % Load			60 % Load		
Component	MW (lb/mole)	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.90	0.87	0.91	0.89	0.88	0.90	0.88	0.89
N_2	28.013	75.38	74.91	73.62	75.33	74.87	73.55	75.33	74.86	73.61
O_2	31.999	13.88	13.87	13.65	13.76	13.74	13.43	13.76	13.71	13.61
CO_2	44.010	3.28	3.22	3.16	3.34	3.28	3.26	3.34	3.30	3.17
H_2O	18.015	6.57	7.11	8.71	6.67	7.22	8.89	6.68	7.25	8.73
	Totals	100.01	100.01	100.01	100.01	100.00	100.01	100.01	100.00	100.01
Exhaust MW (lb/mole)		28.54	28.48	28.30	28.54	28.47	28.29	28.54	28.47	28.30
Exhaust Flow (lb/sec)		712.22	652.78	596.67	579.17	536.67	491.94	487.78	453.89	428.61
Exhaust Temp. (°F)		974	1,001	1,025	1,004	1,037	1,078	1,055	1,091	1,100
(K)		796	811	825	813	831	854	841	861	866
Exhaust O_2 (Vol %, Dry)		14.86	14.93	14.96	14.74	14.81	14.74	14.74	14.78	14.91

Sources: ECT, 1999.
GE, 1999.

Table 9.B. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Simple-Cycle

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	1,566,598	1,466,166	1,370,847	1,300,763	1,235,536	1,171,035	1,133,762	1,082,739	1,034,505
Stack Dia. (ft)	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Stack Dia. (m)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Stack Area (ft^2)	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7
Stack Area (m^2)	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Velocity (fps)	139.1	130.2	121.7	115.5	109.7	104.0	100.7	96.1	91.8
Velocity (m/s)	42.4	39.7	37.1	35.2	33.4	31.7	30.7	29.3	28.0
SCFM, Dry'	538,926	492,193	444,959	437,837	404,317	366,280	368,738	341,869	319,573
ACFM (15% O_2, Dry)	1,499,386	1,377,702	1,260,624	1,266,805	1,183,396	1,113,871	1,103,761	1,041,402	958,307

Sources: ECT, 1999.
GE, 1999.

Table 9.C.I. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Simple-Cycle; First Year of Operations

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	25.0	25.0	25.0	30.0	25.0	25.0	29.0	25.0	46.0
CO (15% O_2)	24.4	24.7	24.8	28.7	24.2	23.9	27.8	24.1	45.3
VOC (ppmvw)	1.4	1.4	1.4	3.0	1.8	1.4	3.0	1.6	4.6
VOC (ppmvd)	1.5	1.5	1.5	3.2	1.9	1.5	3.2	1.7	5.0
VOC (15% O_2)	1.5	1.5	1.5	3.1	1.9	1.5	3.1	1.7	5.0

Sources: ECT, 1999.
GE, 1999.

Table 9.C.II. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Simple-Cycle; Following First Year of Operations

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.0	20.0	20.0	30.0	25.0	25.0	29.0	25.0	46.0
CO (15% O_2)	19.5	19.8	19.9	28.7	24.2	23.9	27.8	24.1	45.3
VOC (ppmvw)	1.4	1.4	1.4	3.0	1.8	1.4	3.0	1.6	4.6
VOC (ppmvd)	1.5	1.5	1.5	3.2	1.9	1.5	3.2	1.7	5.0
VOC (15% O_2)	1.5	1.5	1.5	3.1	1.9	1.5	3.1	1.7	5.0

Sources: ECT, 1999.
GE, 1999.

Table 9.D. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Combined-Cycle

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
		100 % Load			80 % Load			60 % Load		
Component	MW (lb/mole)	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.90	0.90	0.87	0.91	0.89	0.88	0.90	0.88	0.89
N_2	28.013	75.38	74.91	73.62	75.33	74.87	73.55	75.33	74.86	73.61
O_2	31.999	13.88	13.87	13.65	13.76	13.74	13.43	13.76	13.71	13.61
CO_2	44.010	3.28	3.22	3.16	3.34	3.28	3.26	3.34	3.30	3.17
H_2O	18.015	6.57	7.11	8.71	6.67	7.22	8.89	6.68	7.25	8.73
	Totals	100.01	100.01	100.01	100.01	100.00	100.01	100.01	100.00	100.01
Exhaust MW (lb/mole)		28.54	28.48	28.30	28.54	28.47	28.29	28.54	28.47	28.30
Exhaust Flow (lb/sec)		712.22	652.78	596.67	579.17	536.67	491.94	487.78	453.89	428.61
Exhaust Temp. (°F)		248	242	239	235	232	230	226	224	225
(K)		393	390	388	386	384	383	381	380	380
Exhaust O_2 (Vol %, Dry)		14.86	14.93	14.96	14.74	14.81	14.74	14.74	14.78	14.91

Sources: ECT, 1999.
GE, 1999.

Table 9.E. GRU J.R. Kelley Generating Station Repowering Project CC-1 Exhaust Data - General Electric PG7121(EA) CTG Natural Gas-Firing; Combined-Cycle

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	773,030	704,482	645,637	617,063	570,971	524,986	513,523	477,354	454,254
Stack Dia. (ft)	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Stack Dia. (m)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Stack Area (ft^2)	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7
Stack Area (m^2)	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Velocity (fps)	68.6	62.5	57.3	54.8	50.7	46.6	45.6	42.4	40.3
Velocity (m/s)	20.9	19.1	17.5	16.7	15.5	14.2	13.9	12.9	12.3
SCFM, Dry'	538,926	492,193	444,959	437,837	404,317	366,280	368,738	341,869	319,573
ACFM (15% O_2, Dry)	739,864	661,976	593,724	600,953	546,876	499,359	499,935	459,130	420,795

Sources: ECT, 1999.
GE, 1999.

Table 9.F.I. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Combined-Cycle; First Year of Operations

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	25.0	25.0	25.0	30.0	25.0	25.0	29.0	25.0	46.0
CO (15% O_2)	24.4	24.7	24.8	28.7	24.2	23.9	27.8	24.1	45.3
VOC (ppmvw)	1.4	1.4	1.4	3.0	1.8	1.4	3.0	1.6	4.6
VOC (ppmvd)	1.5	1.5	1.5	3.2	1.9	1.5	3.2	1.7	5.0
VOC (15% O_2)	1.5	1.5	1.5	3.1	1.9	1.5	3.1	1.7	5.0

Sources: ECT, 1999.
GE, 1999.

Table 9.F.II. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Natural Gas-Firing; Combined-Cycle; Following First Year of Operations

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.0	20.0	20.0	30.0	25.0	25.0	29.0	25.0	46.0
CO (15% O_2)	19.5	19.8	19.9	28.7	24.2	23.9	27.8	24.1	45.3
VOC (ppmvw)	1.4	1.4	1.4	3.0	1.8	1.4	3.0	1.6	4.6
VOC (ppmvd)	1.5	1.5	1.5	3.2	1.9	1.5	3.2	1.7	5.0
VOC (15% O_2)	1.5	1.5	1.5	3.1	1.9	1.5	3.1	1.7	5.0

Sources: ECT, 1999.
GE, 1999.

Table 10.A. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Distillate Fuel Oil-Firing; Simple-Cycle

A. Exhaust Molecular Weight (MW)

		Exhaust Gas Composition - Volume %								
	MW	100 % Load			80 % Load			60 % Load		
Component	(lb/mole)	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.89	0.88	0.87	0.89	0.88	0.86	0.89	0.88	0.88
N_2	28.013	73.85	73.54	72.61	73.71	73.49	72.65	73.88	73.68	72.90
O_2	31.999	13.17	13.21	13.14	12.75	12.92	12.95	12.86	13.05	13.20
CO_2	44.010	4.61	4.52	4.40	4.87	4.72	4.54	4.83	4.66	4.41
H_2O	18.015	7.49	7.85	8.98	7.79	8.00	9.00	7.55	7.73	8.61
	Totals	100.01	100.00	100.00	100.01	100.01	100.00	100.01	100.00	100.00
Exhaust MW (lb/mole)		28.64	28.58	28.45	28.63	28.59	28.46	28.65	28.61	28.49
Exhaust Flow (lb/sec)		728.61	666.67	607.50	573.33	537.22	499.72	485.28	458.06	434.44
Exhaust Temp. (°F)		968	996	1,021	1,041	1,058	1,076	1,086	1,099	1,100
(K)		793	809	823	834	843	853	859	866	866
Exhaust O_2 (Vol %, Dry)		14.24	14.34	14.44	13.83	14.04	14.23	13.91	14.14	14.44

Sources: ECT, 1999.
GE, 1999.

Table 10.B. GRU J.R. Kelley Generating Station Repowering Project
CTG Exhaust Data - General Electric PG7121(EA) CTG (Per CTG)
Distillate Fuel Oil-Firing; Simple-Cycle

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	1,590,854	1,486,887	1,384,787	1,316,050	1,248,844	1,180,929	1,146,439	1,092,815	1,041,590
Stack Dia. (ft)	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Stack Dia. (m)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Stack Area (ft^2)	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7
Stack Area (m^2)	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Velocity (fps)	141.2	132.0	122.9	116.8	110.9	104.8	101.8	97.0	92.5
Velocity (m/s)	43.1	40.2	37.5	35.6	33.8	32.0	31.0	29.6	28.2
SCFM, Dry'	544,158	496,873	449,364	426,878	399,630	369,409	361,978	341,503	322,185
ACFM (15% O_2, Dry)	1,662,197	1,524,525	1,380,839	1,454,768	1,335,205	1,214,756	1,255,652	1,154,759	1,041,680

Sources: ECT, 1999.
GE, 1999.

Table 10.C. GRU J.R. Kelley Generating Station Repowering Project
CTG Exhaust Data - General Electric PG7121(EA) CTG (Per CTG)
Distillate Fuel Oil-Firing; Simple-Cycle

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO (15% O_2)	17.7	18.0	18.3	16.7	17.2	17.7	16.9	17.5	18.3
VOC (ppmvw)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
VOC (ppmvd)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
VOC (15% O_2)	3.3	3.4	3.5	3.2	3.3	3.4	3.2	3.3	3.5

Sources: ECT, 1999.
GE, 1999.

Table 10.D. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Distillate Fuel Oil-Firing; Combined-Cycle

A. Exhaust Molecular Weight (MW)

Component	MW (lb/mole)	Exhaust Gas Composition - Volume %								
		100 % Load			80 % Load			60 % Load		
		20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
	Case	1	4	7	2	5	8	3	6	9
Ar	39.944	0.89	0.88	0.87	0.89	0.88	0.86	0.89	0.88	0.88
N_2	28.013	73.85	73.54	72.61	73.71	73.49	72.65	73.88	73.68	72.90
O_2	31.999	13.17	13.21	13.14	12.75	12.92	12.95	12.86	13.05	13.20
CO_2	44.010	4.61	4.52	4.40	4.87	4.72	4.54	4.83	4.66	4.41
H_2O	18.015	7.49	7.85	8.98	7.79	8.00	9.00	7.55	7.73	8.61
	Totals	100.01	100.00	100.00	100.01	100.01	100.00	100.01	100.00	100.00
Exhaust MW (lb/mole)		28.64	28.58	28.45	28.63	28.59	28.46	28.65	28.61	28.49
Exhaust Flow (lb/sec)		728.61	666.67	607.50	573.33	537.22	499.72	485.28	458.06	434.44
Exhaust Temp. (°F)		302	296	291	292	286	283	289	280	279
(K)		423	420	417	418	414	413	416	411	411
Exhaust O_2 (Vol %, Dry)		14.24	14.34	14.44	13.83	14.04	14.23	13.91	14.14	14.44

Sources: ECT, 1999.
GE, 1999.

Table 10.E. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Distillate Fuel Oil-Firing; Combined-Cycle

B. Exhaust Flow Rates

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
ACFM	849,347	772,242	702,585	659,603	613,480	571,551	555,052	518,929	493,687
Stack Dia. (ft)	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5	15.5
Stack Dia. (m)	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
Stack Area (ft^2)	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7	187.7
Stack Area (m^2)	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
Velocity (fps)	75.4	68.6	62.4	58.6	54.5	50.7	49.3	46.1	43.8
Velocity (m/s)	23.0	20.9	19.0	17.8	16.6	15.5	15.0	14.0	13.4
SCFM, Dry'	544,158	496,873	449,364	426,878	399,630	369,409	361,978	341,503	322,185
ACFM (15% O_2, Dry)	887,436	791,790	700,582	729,129	655,904	587,923	607,927	548,344	493,730

Sources: ECT, 1999.
GE, 1999.

Table 10.F. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Exhaust Data - General Electric PG7121(EA) CTG
Distillate Fuel Oil-Firing; Combined-Cycle

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

	Flow Rates (ft^3/min)								
	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
CO (ppmvd)	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
CO (15% O_2)	17.7	18.0	18.3	16.7	17.2	17.7	16.9	17.5	18.3
VOC (ppmvw)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
VOC (ppmvd)	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
VOC (15% O_2)	3.3	3.4	3.5	3.2	3.3	3.4	3.2	3.3	3.5

Sources: ECT, 1999.
GE, 1999.

Table 11. GRU J.R. Kelley Generating Station Repowering Project
CC-1 Fuel Flow Data - General Electric PG7121(EA) CTG

A. Natural Gas-Firing

	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV (MMBtu/hr)	1,082.7	977.0	881.7	903.1	825.7	755.8	766.8	706.7	646.1
Fuel Rate[1] (lb/hr)	46,777	42,210	38,093	39,018	35,674	32,654	33,129	30,532	27,914
Fuel Rate[2] (10^6 ft^3/hr)	1.057	0.954	0.861	0.882	0.806	0.738	0.749	0.690	0.631
Fuel Rate (lb/sec)	12.994	11.725	10.581	10.838	9.909	9.070	9.202	8.481	7.754

B. Distillate Fuel Oil-Firing

	100 % Load			80 % Load			60 % Load		
	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F	20 °F	59 °F	95 °F
Case	1	4	7	2	5	8	3	6	9
Heat Input - HHV (MMBtu/hr)	1,120.5	1,008.5	899.1	940.9	854.4	768.3	794.8	724.6	653.0
Fuel Rate[3] (lb/hr)	57,609	51,851	46,226	48,375	43,928	39,501	40,864	37,254	33,573
Fuel Rate[4] (10^3 gal/hr)	8.001	7.201	6.420	6.719	6.101	5.486	5.675	5.174	4.663
Fuel Rate (lb/sec)	16.003	14.403	12.841	13.438	12.202	10.973	11.351	10.348	9.326

[1] Natural gas heat content of 23,146 Btu/lb (HHV).

[2] Natural gas density of 0.0443 lb/ft^3.

[3] Distillate fuel oil heat content of 19,450 Btu/lb (HHV).

[4] Distillate fuel oil density of 7.20 lb/gal.

Sources: ECT, 1999.
GE, 1999.
GRU, 1999.

J.R. KELLY GENERATING STATION
REPOWERING PROJECT
EXPLANATION OF APPENDIX D EMISSIONS DATA

Emissions data for the General Electric PG7121 (EA) combustion turbine are provided in Appendix D, Tables 1 through 11. The following sections explain provide the basis for each emission rate calculation.

Note that the calculation results provided in Tables 1 through 11 used the 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 11 may, in some cases, produce slightly different results because the Tables do not display all of the 15 digits used by the electronic spreadsheet.

Table 1.: CC-1 Operating Scenarios

Operating scenarios identified in Table 1 represent the range of loads (60 to 100 percent), approximate ambient temperatures (20 to 95°F), fuel types (natural gas and distillate fuel oil), and modes (simple and combined cycle) under which CC-1 will operate.

Table 2.A.: CC-1 Hourly Emission Rates, Natural Gas, First Year Operations

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 Method 5B or 17. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 2; 20°F ambient temperature, 80% load

GE PM/PM_{10} = 5.0 lb/hr

PM/PM_{10} = 5.0 lb/hr x 0.126 = 0.63 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 2.0 gr S/100 ft^3, natural gas heat content of 23,146 Btu/lb, natural gas density of 0.04425 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: Case 4; 59°F ambient temperature, 100% load

GE CT heat Input = (977.0 x 10^6 Btu/hr) [HHV]

Fuel Flow = (977.0 x 10^6 Btu/hr) x (1 lb / 23,146 Btu NG) [HHV]

Fuel Flow = 42,210 lb/hr NG

SO_2 = (42,210 lb/hr NG) x (2.0 gr S / 100 ft^3) x (ft^3 / 0.04425 lb NG)

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

SO_2 = 5.5 lb/hr

SO_2 = 5.5 lb/hr x 0.126 = 0.69 g/s

C. H_2SO_4

For each ambient temperature and CT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO_2 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 95°F ambient temperature, 100% load

SO_2 = 4.92 lb/hr

H_2SO_4 = (4.92 lb/hr SO_2) x (7.5 / 100) x (98 lb-mole H_2SO_4 / 64 lb-mole SO_2)

H_2SO_4 = 0.565 lb/hr

H_2SO_4 = 0.565 lb/hr x 0.126 = 0.0712 g/s

D. Lead

For each ambient temperature and CT operating load, estimates of lead emission rates were developed using an emission factor from the EPA Electric Utility Hazardous Air Pollutant Study and GE heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

GE CT heat Input = (1,082.7 x 10^6 Btu/hr) [HHV]

Lead Emission Factor = 3.70 x 10^{-7} lb / 10^6 Btu

Lead = (1,082.7 x 10^6 Btu/hr) x (3.70 x 10^{-7} lb / 10^6 Btu)

Lead = 0.0004 lb/hr (Negligible)

E. 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: Case 3; 20°F ambient temperature, 60% load

GE NO_x = 9.0 ppmvd @ 15% O_2 GE NO_x = 25.0 lb/hr

NO_x = 25.0 lb/hr

NO_x = 25.0 lb/hr x 0.126 = 3.15 g/s

F. 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: Case 7; 95°F ambient temperature, 100% load

GE CO = 25.0 ppmvd @ actual O_2 GE CO = 24.8 ppmvd @ 15% O_2 GE CO = 49.0 lb/hr

CO = 49.0 lb/hr

CO = 49.0 lb/hr x 0.126 = 6.17 g/s

G. 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: Case 5; 59°F ambient temperature, 80% load

GE VOC = 1.8 ppmvw @ actual O_2 GE VOC = 1.9 ppmvd @ 15% O_2 GE VOC = 1.8 lb/hr

VOC = 1.8 lb/hr

VOC = 1.8 lb/hr x 0.126 = 0.23 g/s

Table 2.B.: CC-1 Hourly Emission Rates, Natural Gas, Following First Year of Operations

Calculations are the same as described above for Table 2.A. For CO, following the first year of operations the exhaust concentrations at 100% load will be limited to 20.0 ppmvd.

A. 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: Case 7; 95°F ambient temperature, 100% load

GE CO = 20.0 ppmvd @ actual O_2 GE CO = 19.9 ppmvd @ 15% O_2 GE CO = 39.2 lb/hr

CO = 39.2 lb/hr

CO = 39.2 lb/hr x 0.126 = 4.94 g/s

Table 3.: CC-1 Hourly Emission Rates, Distillate Fuel Oil

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 Method 5B or 17. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 2; 20°F ambient temperature, 80% load

GE PM/PM_{10} = 10.0 lb/hr

PM/PM_{10} = 10.0 lb/hr x 0.126 = 1.26 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, distillate fuel sulfur content of 0.05 weight percent, and distillate fuel oil heat content of 19,450 Btu/lb. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 4; 59°F ambient temperature, 100% load

GE CT heat Input = $(1{,}008.5 \times 10^6$ Btu/hr) [HHV]

Fuel Flow = $(1{,}008.5 \times 10^6$ Btu/hr) x (1 lb / 19,450 Btu Oil) [HHV]

Fuel Flow = 51,851 lb/hr Oil

SO_2 = (51,851 lb/hr Oil) x (0.05 lb S / 100 lb Oil) x (2 lb SO_2 / 1 lb S)

SO_2 = 51.9 lb/hr

SO_2 = 51.9 lb/hr x 0.126 = 6.53 g/s

C. H_2SO_4

For each ambient temperature and CT operating load, H_2SO_4 emissions in lb/hr were based on an assumed 7.5% conversion rate by volume of SO_2 to H_2SO_4. Emissions in lb/hr were converted to g/s by multiplying by a conversion factor of 0.126.

Example: Case 7; 95°F ambient temperature, 100% load

SO_2 = 46.2 lb/hr

H_2SO_4 = (46.2 lb/hr SO_2) x (7.5 / 100) x (98 lb-mole H_2SO_4 / 64 lb-mole SO_2)

H_2SO_4 = 5.31 lb/hr

H_2SO_4 = 5.31 lb/hr x 0.126 = 0.669 g/s

D. Lead

For each ambient temperature and CT operating load, estimates of lead emission rates were developed using an emission factor from EPA AP-42 Emission Factor, Table 3.1-4., October 1996, and GE heat input rates.

Example: Case 1; 20°F ambient temperature, 100% load

GE CT heat Input = $(1{,}120.57 \times 10^6$ Btu/hr) [HHV]

Lead Emission Factor = 5.80×10^{-5} lb / 10^6 Btu

Lead = $(1{,}120.5 \times 10^6$ Btu/hr) x (5.80×10^{-5} lb / 10^6 Btu)

Lead = 0.065 lb/hr

E. 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: Case 3; 20°F ambient temperature, 60% load

GE NO_x = 42.0 ppmvd @ 15% O_2 GE NO_x = 129.0 lb/hr

NO_x = 129.0 lb/hr

NO_x = 129.0 lb/hr x 0.126 = 16.25 g/s

F. 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: Case 7; 95°F ambient temperature, 100% load

GE CO = 20.0 ppmvd @ actual O_2 GE CO = 18.3 ppmvd @ 15% O_2 GE CO = 39.0 lb/hr

CO = 39.0 lb/hr

CO = 39.0 lb/hr x 0.126 = 4.91 g/s

G. 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: Case 5; 59°F ambient temperature, 80% load

GE VOC = 3.5 ppmvw @ actual O_2 GE VOC = 3.3 ppmvd @ 15% O_2 GE VOC = 4.0 lb/hr

VOC = 4.0 lb/hr

VOC = 4.0 lb/hr x 0.126 = 0.50 g/s

Table 4.: CC-1 Hourly Emission Rates, Noncriteria Pollutants, Natural Gas

Estimates on noncriteria pollutant emission rates were developed using emission factors from the four references shown at the bottom of Table 4 and GE heat input data for Case 1 (maximum hourly heat input rate which occurs at 20°F ambient temperature, 100% load) and Case 4 (maximum annual average heat input rate which occurs at 59°F ambient temperature, 100% load) for maximum hourly and annual emission estimates, respectively. For annual emission estimates, continuous operation (8,760 hrs/yr) was assumed.

Example: Maximum Hourly Naphthalene; Case 1; 20°F ambient temperature, 100% load

GE CT heat Input = (1,082.7 x 10^6 Btu/hr) [HHV]

Naphthalene Emission Factor = 6.70×10^{-7} lb / 10^6 Btu

Naphthalene = ($1,082.7 \times 10^6$ Btu/hr) x (6.70×10^{-7} lb / 10^6 Btu)

Naphthalene = 7.25×10^{-4} lb/hr

Example: Maximum Annual Naphthalene; Case 4; 59°F ambient temperature, 100% load

GE CT heat Input = (977.0×10^6 Btu/hr) [HHV]

Naphthalene Emission Factor = 6.70×10^{-7} lb / 10^6 Btu

Naphthalene = (977.0×10^6 Btu/hr) x (6.70×10^{-7} lb / 10^6 Btu)

Naphthalene = 6.55×10^{-4} lb/hr

Naphthalene = (6.55×10^{-4} lb/hr) x (8,760 hr/yr) x (ton / 2,000 lb)

Naphthalene = 2.87×10^{-3} ton/yr

Table 5.: CC-1 Hourly Emission Rates, Noncriteria Pollutants, Distillate Fuel Oil

Estimates on noncriteria pollutant emission rates were developed using emission factors from the three references shown at the bottom of Table 5 and GE heat input data for Case 1 (maximum hourly heat input rate which occurs at 20°F ambient temperature, 100% load) and Case 4 (maximum annual average heat input rate which occurs at 59°F ambient temperature, 100% load) for maximum hourly and annual emission estimates, respectively. For annual emission estimates, operation for 1,000 hrs/yr was assumed.

Example: Maximum Hourly Arsenic; Case 1; 20°F ambient temperature, 100% load

GE CT heat Input = ($1,120.5 \times 10^6$ Btu/hr) [HHV]

Arsenic Emission Factor = 4.90×10^{-6} lb / 10^6 Btu

Arsenic = ($1,120.5 \times 10^6$ Btu/hr) x (4.90×10^{-6} lb / 10^6 Btu)

Arsenic = 5.49×10^{-3} lb/hr

Example: Maximum Annual Arsenic; Case 4; 59°F ambient temperature, 100% load

GE CT heat Input = ($1,008.50 \times 10^6$ Btu/hr) [HHV]

Arsenic Emission Factor = 4.90×10^{-6} lb / 10^6 Btu

Arsenic = ($1,008.5 \times 10^6$ Btu/hr) x (4.90×10^{-6} lb / 10^6 Btu)

Arsenic = 4.94×10^{-3} lb/hr

Arsenic = (4.94×10^{-3} lb/hr) x (1,000 hr/yr) x (ton / 2,000 lb)

Arsenic = 2.47×10^{-3} ton/yr

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EXPLANATION OF APPENDIX D EMISSIONS DATA

Table 6.A.: CC-1 Annual Emission Rates, First Year Operations

Annual emission rates were determined using the pollutant hourly rates for Case 4 (59°F , 100 % CT load, natural gas firing) for 7,760 hours per year and pollutant hourly rates for Case 4 (59°F , 100 % CT load, distillate fuel oil firing) for 1,000 hours per year. An example calculation for NO_x follows:

Example: NO_x

Case 4 (natural gas) NO_x Hourly Emission Rate = 32.0 lb/hr
Case 4 (distillate fuel oil) NO_x Hourly Emission Rate = 166.0 lb/hr

Annual NO_x = [(32.0 lb/hr x 7,760 hrs/yr) + (166.0 lb/hr x 1,000 hrs/yr)] / 2000 lb/ton
Annual NO_x = 207.2 ton/yr

Table 6.B.: CC-1 Annual Emission Rates, Following First Year Operations

Annual emission rates were determined as described above for Table 6.B. For CO, Case 4 (natural gas) annual rates are based on a limit of 20 ppmvd. An example calculation for CO follows:

Example: CO

Case 4 (natural gas) CO Hourly Emission Rate = 43.2 lb/hr
Case 4 (distillate fuel oil) CO Hourly Emission Rate = 43.0 lb/hr

Annual CO = [(43.2 lb/hr x 7,760 hrs/yr) + (43.0 lb/hr x 1,000 hrs/yr)] / 2000 lb/ton
Annual CO = 189.1 ton/yr

Table 7.: CC-1 Annual Emission Rates, Noncriteria Pollutants

The maximum hourly noncriteria pollutant emission rates shown in Table 7 represent the **highest** hourly rate for either natural gas or distillate fuel oil combustion; maximum hourly rates are provided in Tables 4 and 5 for natural gas and distillate fuel oil, respectively.

Maximum annual noncriteria pollutant emission rates shown in Table 7 represent the **total** annual rate for both natural gas and distillate fuel oil combustion; maximum annual rates are provided in Tables 4 and 5 for natural gas and distillate fuel oil, respectively.

Example: Maximum Annual Arsenic Emission Rate

Arsenic (natural gas) = 5.99×10^{-4} ton/yr
Arsenic (distillate fuel oil) = 2.47×10^{-3} ton/yr

Arsenic (both fuels) = 5.99×10^{-4} ton/yr + 2.47×10^{-3} ton/yr
Arsenic (both fuels) = 3.07×10^{-3} ton/yr

Table 8.: CC-1 NSPS Subpart GG NO_x Limits

NSPS Subpart GG NO_x limits were calculated for each fuel type (natural gas and distillate fuel oil) based on the GE heats at ISO conditions (59°F, 100% load) and the NSPS Subpart GG NO_x limit equation. Because the GE heat rates were provided on a HHV basis, the rates were adjusted to an 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: 11,730 Btu/kW-hr (HHV)
Natural Gas Heat Content: 20,761 Btu/lb (LHV)
Natural Gas Heat Content: 23,146 Btu/lb (HHV)

Heat Rate at ISO Conditions = [11,730 Btu/kW-hr (HHV)]
x [20,761 Btu/lb (LHV) / 23,146 Btu/lb (HHV)]
Heat Rate at ISO Conditions = 10,521 Btu/kW-hr (LHV)

Heat Rate at ISO Conditions = [10,521 Btu/kW-hr (LHV)] x (1.055056 / 1000)
Heat Rate at ISO Conditions = 11.101 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 / 11.101) + 0] x 10,000
NSPS Subpart GG NO_x Limit = 97.3 ppmvd

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

Table 9.A.: CC-1 Exhaust Data; Natural Gas-Firing; Simple-Cycle Mode

Exhaust gas compositions (volume %), exhaust flow rates (lb/hr), and exhaust temperatures (°F) shown in Table 9A were obtained from the GE performance specification 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: Case 7 (95°F, 100% Load)

MW = [(0.87/100) x 39.944] + [(73.62/100) x 28.013] + [(13.65/100) x 31.999]
+ [(3.16/100) x 44.010] + [(8.71/100) x 18.015]

MW = 28.30 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: Case 1 (20°F, 100% Load)

GE Exhaust Flow Rate: 2,564,000 lb/hr

Exhaust Flow Rate = (2,564,000 lb/hr) x (hr / 3,600 sec)
Exhaust Flow Rate = 712.22 lb/sec

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

Example: Case 8 (95°F, 80% Load)

GE Exhaust Temperature: 1,078 °F

Exhaust Temperature = (1,078 °F + 459.67) / (1.8)
Exhaust Temperature = 854.3 K

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

Example: Case 6 (59°F, 60% Load)

GE Exhaust Oxygen Concentration: 13.71 volume % (wet)
GE Exhaust Water Concentration: 7.25 volume %

Exhaust Oxygen Concentration (dry) = [(13.71) / (100 – 7.25)] x 100
Exhaust Oxygen Concentration = 14.78 volume % (dry)

Table 9.B.: CC-1 Exhaust Data; Natural Gas-Firing; Simple-Cycle Mode

Exhaust gas flow rates (actual, standard, and actual at 15% O_2, dry) were calculated based on the GE data shown in Table 9A. Stack diameter was provided by GRU. Stack exit velocity was calculated based on the exhaust flow rates and calculated stack area.

1. 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 Table 9A and the Ideal Gas Law.

Example: Case 1 (20°F, 100% Load)

GE Exhaust Flow Rate: 712.22 lb/sec (from Table 9A)
Exhaust Gas Molecular Weight: 28.54 lb/lb-mole (From Table 9A)
GE Exhaust Gas Temperature: 974 °F (From Table 9A)
Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (acfm) = (712.22 lb/sec) x (60 sec / min) x (lb-mole / 28.54 lb) x (385.3 ft^3/lb-mole) x [(974 + 460) / (68 + 460)]

Exhaust Gas Flow Rate = 1,566,598 acfm

2. Stack area was calculated based on the stack exit diameter provided by GRU.

Example: All Cases

Stack Exit Diameter: 15.46 ft; 4.72 m

Stack Exit Area = π x (15.46 ft / 2)^2
Stack Exit Area = 187.7 ft^2; 17.4 m^2

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

Example: Case 3 (20°F, 60% Load)

Calculated Actual Exhaust Flow Rate: 1,133,762 ft^3/min (From Table 9B)
Calculated Stack Exit Area: 187.7 ft^2

Stack Exit Velocity = (1,133,762 ft^3/min) x (1 min / 60 sec) x (1 / 187.7 ft^2)
Stack Exit Velocity = 100.7 ft/sec; 30.7 m/sec

4. 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 Table 9A and the Ideal Gas Law.

Example: Case 7 (95°F, 100% Load)

GE Exhaust Flow Rate: 596.67 lb/sec (from Table 9A)
GE Exhaust Gas Moisture Content: 8.71 volume % (from Table 9A)
Exhaust Gas Molecular Weight: 28.30 lb/lb-mole (From Table 9A)
Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dscfm) = (596.67 lb/sec) x (60 sec / min) x (lb-mole / 28.30 lb)
x (385.3 ft^3/lb-mole) x [1 - (8.71 / 100)]

Exhaust Gas Flow Rate = 444,959 dscfm

5 Exhaust gas flow rates, in units of dry, actual cubic feet per minute corrected to 15% O_2, were calculated based on the GE exhaust flow rates (in units of lb/sec), temperatures, moisture and dry oxygen contents, and molecular weights shown in Table 9A and the Ideal Gas Law.

Example: Case 9 (95°F, 60% Load)

GE Exhaust Flow Rate: 428.61 lb/sec (from Table 9A)
GE Exhaust Gas Moisture Content: 8.73 volume % (from Table 9A)
GE Exhaust Gas Temperature: 1,100 °F (From Table 9A)
Calculated Exhaust Oxygen Content: 14.91 volume % (dry)
Atmospheric Oxygen Content: 20.9 volume %
Calculated Exhaust Gas Molecular Weight: 28.30 lb/lb-mole (From Table 9A)
Volume of One lb-mole at 68°F: 385.3 ft^3/lb-mole (Ideal Gas Law)

Exhaust Gas Flow Rate (dacfm @ 15% O_2) = (428.61 lb/sec) x (60 sec / min)
x (lb-mole / 28.30 lb) x (385.3 ft^3/lb-mole)
x [(1,100 + 460) / (68 + 460)] x [1 - (8.73 / 100)]
x [(20.9 – 14.91) / (20.9 – 15.0)]

Exhaust Gas Flow Rate = 958,307 dacfm @ 15% O_2

Table 9.C.I.: CC-1 Exhaust Data; Natural Gas-Firing; Simple-Cycle Mode

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 Table 9A.

Example: CO, Case 4 (59°F, 100% Load)

GE CO Exhaust Concentration: 25.0 ppmvd
Calculated Exhaust Oxygen Content: 14.93 volume % (dry)
Atmospheric Oxygen Content: 20.9 volume %

Exhaust CO Concentration (ppmvd @ 15% O_2) = (25.0 ppmvd) x [(20.9 – 15.0) / (20.9 – 14.93)]
Exhaust CO Concentration = 24.7 ppmvd @ 15% O_2

Example: VOC, Case 7 (95°F, 100% Load)

GE VOC Exhaust Concentration: 1.4 ppmvw
GE Exhaust Moisture Content: 8.71 volume %
Calculated Exhaust Oxygen Content: 14.96 volume % (dry)
Atmospheric Oxygen Content: 20.9 volume %

Exhaust VOC Concentration (ppmvd) = (1.4 ppmvw) / [1 - (8.71 / 100)]
Exhaust VOC Concentration = 1.5 ppmvd

Exhaust VOC Concentration (ppmvd @ 15% O_2) = (1.5 ppmvd) x [(20.9 – 15.0) / (20.9 – 14.96)]
Exhaust VOC Concentration = 1.5 ppmvd @ 15% O_2

Table 9.C.II.: CC-1 Fuel Flow Rate; CC-1 Exhaust Data; Natural Gas-Firing; Simple-Cycle Mode

CO and VOC exhaust concentrations shown in Table 9.C.II. were calculated in the same manner as described above for Table 9.C.I.

Tables 9.D. through 9.F.II.: CC-1 Exhaust Data; Natural Gas-Firing; Combined-Cycle Mode

Values provided in Tables 9.D. through 9.F.II. were calculated in the same manner as described above for Tables 9.A. through 9.C.II. The primary difference between the two sets of tables is the lower stack exhaust exit temperatures for the combined-cycle mode operation. Note that the emission rates remain the same because the HRSG is unfired; i.e., does not include supplemental duct burner firing.

Tables10.A. through 10.C.: CC-1 Exhaust Data; Distillate Fuel Oil-Firing; Simple-Cycle Mode

Values provided in Tables 10.A. through 10.C. for distillate fuel oil-firing were calculated in the same manner as described above for Tables 9.A. through 9.C.II for natural gas-firing.

Tables10.D. through 10.F.: CC-1 Exhaust Data; Distillate Fuel Oil-Firing; Combined-Cycle Mode

Values provided in Tables 10.D. through 10.F. for distillate fuel oil-firing were calculated in the same manner as described above for Tables 9.D. through 9.F.II for natural gas-firing.

Table 11: CC-1 Fuel Flow Rate

Data shown in Table 11 is based on GE heat input data and the heat contents and densities of natural gas and distillate fuel oil.

Example: Natural Gas Case 5 (59°F, 80% load)

GE Heat Input: 825.7 x 10^6 Btu/hr (HHV)
Natural Gas Heat Content: 23,146 Btu/lb (HHV)
Natural Gas Density: 0.04425 lb/ft^3

Fuel Flow Rate (lb/hr) = (825.7 x 10^6 Btu/hr) / (23,146 Btu/lb)
Fuel Flow Rate = 35,674 lb/hr

Fuel Flow Rate (10^6 ft^3/hr) = [(35,674 lb/hr) / (0.04425 lb/ft^3)] x 10^{-6}
Fuel Flow Rate = 0.806 x 10^6 ft^3/hr

Example: Distillate Fuel Oil Case 4 (59°F, 100% load)

GE Heat Input: 1,008.5 x 10^6 Btu/hr (HHV)
Distillate Fuel Oil Heat Content: 19,450 Btu/lb (HHV)
Distillate Fuel Oil Density: 7.20 lb/gal

Fuel Flow Rate (lb/hr) = (1,008.5 x 10^6 Btu/hr) / (19,450 Btu/lb)
Fuel Flow Rate = 51,851 lb/hr

Fuel Flow Rate (10^3 gal/hr) = [(51,851 lb/hr) / (7.20 lb/gal)] x 10^{-3}
Fuel Flow Rate = 7.201 x 10^3 gal/hr

ATTACHMENT E

PSD NETTING ANALYSIS

Attachment E - GRU J.R. Kelley Generating Station Repowering Project
CC-1/Unit 8 Emissions Netting Analysis

	Unit 8 (tpy)										
	1994	1995	1996	1997	1998	5-Yr Avg	97,98 Avg	CC-1 (tpy)	Net Increase (tpy)	PSD Threshold (tpy)	PSD Review (Y/N)
Gas Usage (10^6 ft^3)	730.8	1,324.2	830.0	871.7	837.0	918.7	854.4	N/A	N/A	N/A	N/A
Oil Usage (10^3 gal)	130.3	525.0	369.3	108.2	281.0	282.8	194.6	N/A	N/A	N/A	N/A
Wt % S	0.99	1.64	1.62	1.47	1.53	1.45	1.50	N/A	N/A	N/A	N/A
NO_x AP-42 (1998)	105.4	197.7	124.9	124.6	123.8	135.3	124.2	207.2	83.0	40.0	Y
AOR	205.4	381.7	240.7	243.3	125.1	239.2	184.2	207.2	23.0	40.0	N
CEMS Data Heat Input (MMBtu/yr)	N/A	1,526,234	999,498	988,227	1,008,382	1,130,585	998,305				
NO_x (lb/MMBtu)	N/A	0.184	0.175	0.190	0.187	0.184	0.189				
NO_x (ton/yr)	N/A	140.4	87.5	93.9	94.3	104.0	94.1	207.2	**113.1**	**40.0**	**Y**
CO AP-42 (1998)	31.0	56.9	35.8	36.9	35.9	39.3	36.4	231.0	194.7	100.0	Y
AOR	14.9	27.8	17.5	17.7	N/A	19.5	17.7	231.0	**213.3**	**100.0**	**Y**
SO_2 AP-42 (1998)	10.4	68.0	47.2	12.7	34.0	34.5	23.4	47.1	23.7	40.0	N
AOR	15.8	69.0	47.2	12.8	34.3	35.8	23.6	47.1	23.5	40.0	N
CEMS	N/A	73.4	41.1	16.8	41.7	43.3	29.3	47.1	**17.8**	**40.0**	**N**
H_2SO_4* AP-42 (1998)	0.5	3.1	2.2	0.6	1.6	1.6	1.1	5.4	4.3	7.0	N
AOR	0.7	3.2	2.2	0.6	1.6	1.6	1.1	5.4	4.3	7.0	N
CEMS	N/A	3.4	1.9	0.8	1.9	2.0	1.3	5.4	**4.1**	**7.0**	**N**
PM_{10} AP-42 (1998)	1.3	3.9	2.6	1.4	2.2	2.3	1.8	24.4	**22.6**	**15.0**	**Y**
AOR	1.9	5.3	3.6	1.9	5.6	3.7	3.8	24.4	20.7	15.0	Y
PM AP-42 (1998)	1.3	3.9	2.6	1.4	2.2	2.3	1.8	24.4	**22.6**	**25.0**	**N**
AOR	1.9	5.3	3.6	1.9	5.6	3.7	3.8	24.4	20.7	25.0	N
VOC AP-42 (1998)	2.1	3.8	2.4	2.4	2.4	2.6	2.4	9.2	**6.8**	**40.0**	**N**
AOR	0.6	N/A	N/A	N/A	N/A	0.6	N/A	N/A	N/A	40.0	N/A

*Assumes 3% conversion of SO_2 to H_2SO_4.
Note: Bold and highlighted data represents values selected for PSD netting purposes.

Sources: ECT, 1999.
GRU, 1999.

ATTACHMENT F

DISPERSION MODELING FILES

ATTACHMENT F

DISPERSION MODELING FILES (on diskette)

Distribution was limited to the following:

Florida Dept. of Environmental Protection

- Permitting Engineer
- Meteorologist

Gainesville Regional Utilities

- Sr. Electric Utility Environmental Engineer

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 Allowable |  poll Test |  test Meth |  History |  Return |  eXit
                          Emission Unit Pollutant
                                                                        ARMINV71
     POINT AIRS ID 0010005  STATUS  A    OFFICE NED   NE: JACKSONVILLE
 SITE NAME JOHN R KELLY POWER PLANT          COUNTY  ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU/ID  008  #8 UNIT       S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5     A ST A

   Pollutant NOX       Nitrogen Oxides
      Status A ACTIVE                       # Allow 001  % Control Efficiency
    Pri Cont                                   Sec Cont
   Reg Class

 Potential Emission     306.350000Lb/Hr        1338.140000Ton/Yr  Synth Ltd
    Emission Method 3  CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTE
    Emission Factor    550.000000  Act Emis     117.000000Tons/Yr   Year 1998
               Unit 27  LB/MMCF BURNED      Emis Fac Ref AP42(1.4-2
   Emis Calculation
 Est Fugitive Lower                          Upper               Tons/Yr
  Pollutant Comment FOR NATURAL GAS/ INVENTORY PURPOSES ONLY

Enter Pollutant Code
Count: *1                                                     <List><Replace>
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Allowable | poll Test | test Meth | History | Return | eXit

Emission Unit Pollutant

ARMINV71

POINT AIRS ID 0010005 STATUS A OFFICE NED NE: JACKSONVILLE
SITE NAME JOHN R KELLY POWER PLANT COUNTY ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU ID 008 #8 UNIT S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5 A ST A

Pollutant NOX Nitrogen Oxides
Status A ACTIVE # Allow 001 % Control Efficiency
Pri Cont Sec Cont
Reg Class

Potential Emission 306.350000Lb/Hr 1338.140000Ton/Yr Synth Ltd
Emission Method 3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTE
Emission Factor 550.000000 Act Emis 117.000000Tons/Yr Year 1998
Unit 27 LB/MMCF BURNED Emis Fac Ref AP42(1.4-2
Emis Calculation
Est Fugitive Lower Upper Tons/Yr
Pollutant Comment FOR NATURAL GAS/ INVENTORY PURPOSES ONLY

Enter Pollutant Code
Count: *1 <List><Replace>

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AOR & SIP

ARMINV77

POINT AIRS ID 0010005 STATUS A OFFICE NED NE: JACKSONVILLE
SITE NAME JOHN R KELLY POWER PLANT COUNTY ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU ID 008 #8 UNIT S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5 A ST A

CA AOR Activity AOR ANNUAL OPERATIN Done 09-JUL-1998 Due 30-SEP-1998 CS IN

AOR Pollutant

Pollutant/Emis Method		Act Emis Sum	Actual Annual Emission Calculat
CO	Carbon Monoxide	17.700000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
NOX	Nitrogen Oxides	243.300000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
PM	Particulate Matter -	2.200000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		

Pollutant:CO Allowable Emissions (TPY): 97.320000

Enter Pollutant Code
Count: 3 v <List><Replace>

aor segMent | aor seG`poll | sIp seg poll | aor Poll | Activity |

AOR & SIP

ARMINV77

POINT AIRS ID 0010005 STATUS A OFFICE NED NE: JACKSONVILLE
SITE NAME JOHN R KELLY POWER PLANT COUNTY ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU ID 008 #8 UNIT S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5 A ST A

CA AOR Activity AOR ANNUAL OPERATIN Done 09-JUL-1998 Due 30-SEP-1998 CS IN

AOR Pollutant

Pollutant/Emis Method		Act Emis Sum	Actual Annual Emission Calculat
CO	Carbon Monoxide	17.700000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
NOX	**Nitrogen Oxides**	**243.300000TPY**	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
PM	Particulate Matter -	2.200000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		

Pollutant:NOX Allowable Emissions (TPY): 1338.140000

Enter Pollutant Code
Count: 3 v <List><Replace>

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AOR & SIP

ARMINV77

POINT AIRS ID 0010005 STATUS A OFFICE NED NE: JACKSONVILLE
SITE NAME JOHN R KELLY POWER PLANT COUNTY ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU ID 008 #8 UNIT S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5 A ST A

CA AOR Activity AOR ANNUAL OPERATIN Done 02-AUG-1999 Due 30-SEP-1999 CS IN

AOR Pollutant

Pollutant/Emis Method		Act Emis Sum	Actual Annual Emission Calculat
CO	Carbon Monoxide	0.300000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
NOX	**Nitrogen Oxides**	**117.000000TPY**	
PM	Particulate Matter -	5.000000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		

Pollutant:NOX Allowable Emissions (TPY): 1338.140000

Enter Pollutant Code
Count: 3 v <List><Replace>

aor segMent | aor seG poll | sIp seg poll | aor Poll | Activity |

AOR & SIP

ARMINV77

POINT AIRS ID 0010005 STATUS A OFFICE NED NE: JACKSONVILLE
SITE NAME JOHN R KELLY POWER PLANT COUNTY ALACHUA
OWNER/COMP GAINESVILLE REGIONAL UTILITIES

EU ID 008 #8 UNIT S-10135 58MVA (NAT GAS)584.5 (#6FO)539.5 A ST A

CA AOR Activity AOR ANNUAL OPERATIN Done 09-JUL-1998 Due 30-SEP-1998 CS IN

AOR Pollutant

Pollutant/Emis Method		Act Emis Sum	Actual Annual Emission Calculat
CO	Carbon Monoxide	17.700000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
NOX	Nitrogen Oxides	243.300000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		
PM	Particulate Matter -	2.200000TPY	
	3 CALCULATED USING EMISSION FACTOR FROM AP-42/FIRE SYSTEM.		

Pollutant:CO Allowable Emissions (TPY): 97.320000

Enter Pollutant Code
Count: 3 v <List><Replace>

Table 1-1, Summary of Air Pollutant Standards and Terms

City of Gainesville, GRU
J. R. Kelly Generating Station

50 MW

FINAL Permit No.: 0010005-001-AV
Facility ID No.: 0010005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
-008	Fossil Fuel Fired Steam Generator Unit No. 8

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuels	Hours/Year	Standards	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citations	See permit conditions
VE	Nat. Gas or Nos. 4, 5, 6 F.O.	8760	20% opacity***					62-296.405(1)(a), F.A.C.	III.B.4.
VE(SB)**		1095	60% opacity****					62-210.700(3), F.A.C.	III.B.5.
PM	Nos. 4, 5, 6 F.O.	8760	0.1 lb/MMBtu			53.95	236.3	62-296.405(1)(b), F.A.C.	III.B.6.
PM(SB)**	Nos. 4, 5, 6 F.O.	1095	0.3 lb/MMBtu			161.9	88.61	62-210.700(3), F.A.C.	III.B.7.
SO2	Nos. 4, 5, 6 F.O.	8760	2.75 lb/MMBtu			1,483.6	6,498.30	62-296.405(1)(c)j., F.A.C.	III.B.8.
SO2	Nos. 4, 5, 6 F.O.	8760	2.50% sulfur content by weight on liquid fuels						III.B.9.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** SB refers to "soot blowing" and "load change"
*** Except for one two-minute period per hour up to 40%
**** Except for four six-minute periods up to 100%

[electronic file name: 00100051.xls]

Table 1-1, Summary of Air Pollutant Standards and Terms

City of Gainesville, GRU
J. R. Kelly Generating Station

FINAL Permit No.: 0010005-001-AV
Facility ID No.: 0010005

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No. **Brief Description** 19 MW
-006 Fossil Fuel Fired Steam Generator Unit No. 6

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuels	Hours/Year	Standards	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citations	See permit conditions
VE	Nat. Gas	8760	20% opacity					62-296.406(1), F.A.C.	III.A.4.
VE(SB)**	Nat. gas	1095	60% opacity					62-210.700(3), F.A.C.	III.A.5.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** SB refers to "soot blowing" and "load change".

187.3 mm BTU/hr

[electronic file name: 00100051.xls]

ELSA—Version 1.3c.07-b2

Facility Name:
Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Facility ID: 0010005

Disk 1 of 1

Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Dispersion Modeling Files

Disk 2 of 3

Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Dispersion Modeling Files

Disk 3 of 3

Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Dispersion Modeling Files

Disk 1 of 3

Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Dispersion Modeling Files

Disk 2 of 3

Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Dispersion Modeling Files

Disk 3 of 3

ACCO 3-1/2" Loose Leaf Diskette Panel

Stock No. [illegible], MADE IN MEXICO

ELSA—Version 1.3c.07-b2

Facility Name:
Gainesville Regional Utilities
J.R. Kelly Station
Repowering Project
Facility ID: 0010005

Disk 1 of 1

0010005-002

AC 276-psd #