Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 17, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

Re: DEP File No. 0010005-002-AC (PSD-FL-276
J. R. Kelly Generating Station – Combined Cycle Project

Dear Mr. Kurtz:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the combined cycle project at the J. R. Kelly Generating Station near downtown Gainesville, Alachua County. The Department's Intent to Issue Air construction Permit and the "Public Notice of Intent to Issue Air Construction Permit" are also included.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within 7 (seven) days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Ms. Teresa Heron at 850/921-9529.

Sincerely,

C. H. Fancy, P.E., Chief,
Bureau of Air Regulation

CHF/aal

Enclosures

In the Matter of an
Application for Permit by:

Mr. Michael L. Kurtz, General Manager
City of Gainesville, GRU
Post Office Box 147117
Gainesville, Florida 32614-7117

DEP File No. 0010005-002-AC (PSD-FL-276)
Combined Cycle Repowering Project
Alachua County

______________________________/

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project, detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination, for the reasons stated below.

The applicant, GRU, applied on September 7, 1999 to the Department for an air construction permit to install a nominal 133 megawatt combined cycle unit and auxiliary equipment and to retire the conventional boiler presently providing steam to the Unit 8 steam turbine-electrical generator at the J. R. Kelly Generating Station near downtown, Gainesville, Alachua County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed work.

The Department intends to issue this air construction permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

The Department will issue the final permit with the attached conditions unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments from 7 to 9 p.m. on January 12, 2000 at the Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Alachua County.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

Executed in Tallahassee, Florida.

C H Fancy

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE AIR CONSTRUCTION PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12-17-99 to the person(s) listed:

Michael L. Kurtz*
Yolanta Jonynas, GRU
Chair, Alachua County BCC*
Gregg Worley, EPA
John Bunyak, NPS
Chris Kirts, DEP NED
Pat Reynolds, DEP Gainesville
Tom Davis, ECT

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Kim Tober 12-17-99
(Clerk) (Date)

Z 031 391 905

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

Do not use for International Mail *(See reverse)*

Sent to Michael Kurtz	
Street & Number GRU	
Post Office, State, & ZIP Code Gainesville Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date CC1CCC5-002-AC PSD-FI-276	12-17-99

PS Form **3800**, April 1995

Is your RETURN ADDRESS completed on the reverse side?

- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

...e follow... ...an extra fee:

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:

Michael Kurtz
City of Gainesville, GRU
P O Box 147117 (A134)
Gainesville, Fl
32614-7117

4a. Article Number
Z 031 391 905

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery
DEC 20 1999

5. Received By: *(Print Name)*
Lanay Smith

8. Addressee's Address *(Only if requested and fee is paid)*

6. Signature: *(Addressee or Agent)*
X Lanay Smith

PS Form 3811, ...

Thank you for using Return Receipt Service.

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Alachua County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Gainesville Regional Utilities. The permit is to construct a nominal 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM_{10}) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7717.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50 MW via the existing Unit 8 steam-driven electrical generator. Upon installation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation; and a cooling tower (existing).

Emissions of PM_{10} and CO will be controlled by good combustion of clean pipeline supplied natural gas or maximum, 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM_{10} is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr) while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NO_X) emissions will be controlled by Dry Low NO_X technology capable of achieving 9 parts per million by volume (ppmvd) at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @15% O_2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels.

PSD and BACT do not apply for NO_X, SO_2, SAM, PM and VOC emissions. The maximum future potential (i.e. permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM_{10}	296	1.8	24.4	22.6	15
SAM	160	1.3	5.4	4.1	7
SO_2	6,498	29	47.1	18	40
NO_X	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	171 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NO_X increase will be less than 40 TPY and thus exempt from PSD for that pollutant.

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments. The meeting will be held from 7 to 9 p.m. on January 12, 2000 at the GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue in Gainesville.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Dept. of Environmental Protection	Dept. Environmental Protection	Dept. of Environmental Protection
Bureau of Air Regulation	Northeast District Office	Northeast District Branch
111 S. Magnolia Drive, Suite 4	7825 Baymeadows Way, Suite 200B	101 NW 75 Street, Suite 3
Tallahassee, Florida 32301	Jacksonville, Florida 322256-7590	Gainesville, Florida 32607
Telephone: 850/488-0114	Telephone: 904/448-4300	Telephone: 352/333-2850
Fax: 850/922-6979	Fax: 904/448-4363	Fax: 352/333-2856

The complete project file includes the Draft Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Gainesville Regional Utilities

J.R. Kelly Generating Station
Gainesville, Alachua County

133 Megawatt Combined Cycle Unit CC-1
Repowering of Unit 8

Facility I.D. No. 0010005
PSD-FL-276

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

December 17, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

City of Gainesville Utilities
Gainesville Regional Authority (GRU)
Post Office Box 147117 (A136)
Gainesville, Florida 32614-7117

Authorized Representative: Michael L .Kurtz – General Manager

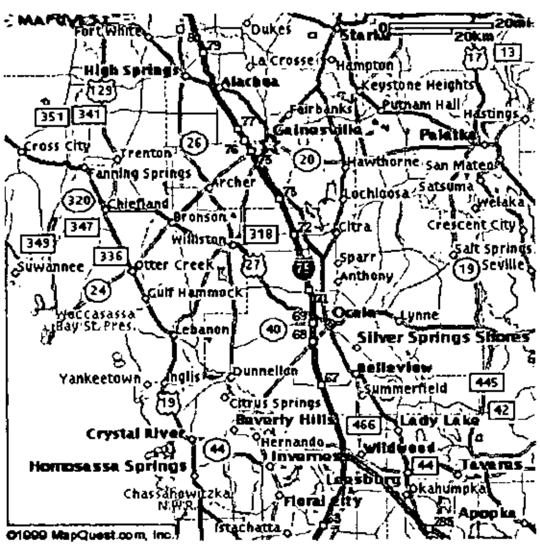
1.2 Reviewing and Process Schedule

09-07-99:	Date of receipt of application
10-06-99:	BAR incompleteness letter
10-26-99:	Received initial GRU response to Department incompleteness letter
11-12-99:	Received additional GRU response to address U.S. FWS Comments
12-02-99:	Received further GRU response to address U.S. EPA comments
12-02-99:	Application deemed complete
12-16-99:	Received letter accepting nitrogen oxides emission cap.

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figures 1 and 2 below. The J.R. Kelly Generating Station is located at 605 SE 3rd Street near the Downtown area of Gainesville, Alachua County. This site approximately 102 kilometers (km) south of Okefenokee National Wildlife Refuge (NWR), a PSD Class I Area. The site is 103 km northeast of the Chassahowitzka NWR Class I PSD Areas. The UTM coordinates of this facility are Zone 17; 372.0 km E; 3,280.2 km N.



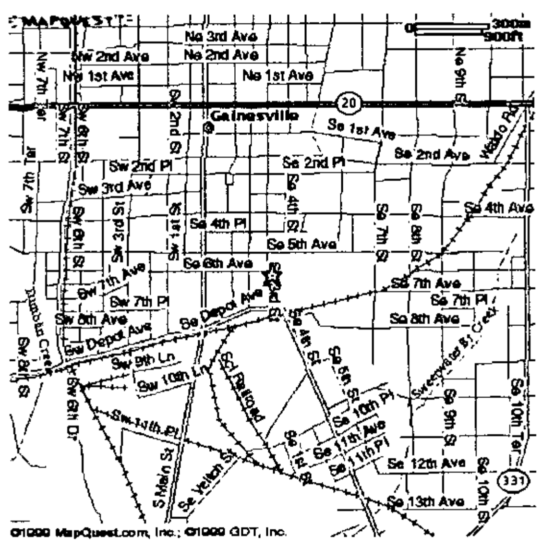


Figure 1 – Regional Location **Figure 2 – Project Location, Gainesville**

2.2 Standard Industrial Classification Codes (SIC)

Industry Group No.	49	Electric, Gas, and Sanitary Services
Industry No.	4911	Electric Services

2.3 Facility Category

This existing facility (see Figure 3) presently generates electric power from two operational boilers and turbines (Units 7 and 8); three simple cycle combustion turbines (Units 1, 2,and 3); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancillary support equipment. Unit Nos. 7 and 8 have nominal nameplate electrical generation capacities of 25 and 50 MW respectively, and are fired primarily with natural gas with No.6 fuel oil serving as a back-up fuel source. Combustion turbine Units 1, 2, and 3 each have a nominal nameplate electrical generating capacity of 16 MW and are fired with natural gas and distillate fuel oil.

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY. The facility is within an industry included in the list of the 28 Major Facility Categories per Table 212.400-1, F.A.C. Because present emissions are greater than 100 TPY for NO_X, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

As a Major Facility, project emissions greater than: Significant Emission Rates given in Table 212.400-2 (100 TPY of CO; 40 TPY of NO_X, SO_2, or VOC, 25/15 TPY of PM/PM_{10}) require review per the PSD rules and a determination of Best Available Control Technology (BACT). This facility is also subject to the Title IV Acid Rain Program, 40 CFR 72 and must apply for an Acid Rain Permit at least 24 months before start up. (Application received January 29,1999)

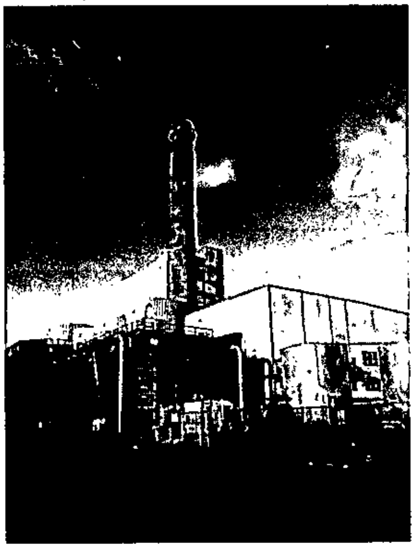


Figure 3 – J.R. Kelly Plant

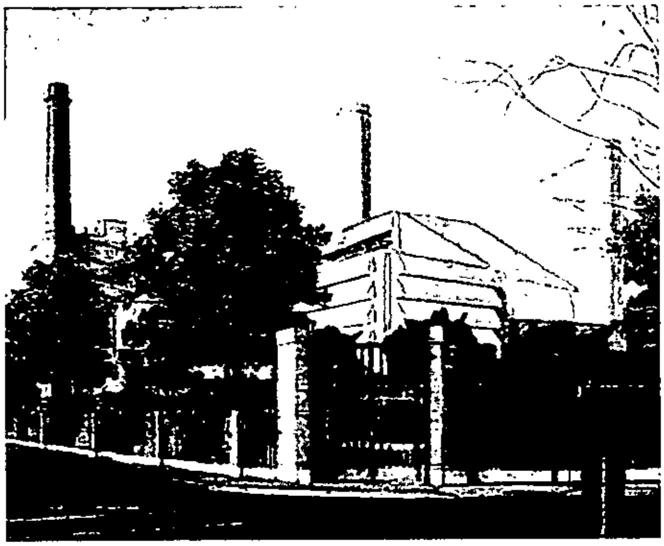


Figure 4 – Artist's Rendition of New Unit CC-1

3. PROJECT DESCRIPTION

This permit addresses the following emissions unit:

EMISSION UNIT	SYSTEM	Emission Unit Description
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

GRU proposes to construct/install a nominal dual fuel 133 megawatt (MW) combined cycle combustion turbine (Unit CC-1), at the existing J.R. Kelly Generating Station (see Figure 4 above). The project includes: a nominal dual fuel 83 MW, General Electric PG7121EA (7EA) combustion turbine-electrical generator fired primarily with pipeline natural gas; an unfired heat recovery steam generator (HRSG); two stacks; and ancillary equipment. The new unit will employ evaporative cooling and use the existing infrastructure including the existing Unit 8 steam turbine electrical generator, oil storage and support equipment. GRU will at times operate the unit in simple cycle mode. The existing Unit 8 boiler will be shut down and dismantled.

The turbine will be equipped with Dry Low NO_X (DLN) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. The turbine will have a nominal heat input rating of 1083 mmBtu/hr (gas) and 1121 mmBtu/hr (oil) based on the higher heat value (HHV) of the fuel and while operating at 20 °F and 100% load.

The main fuel will be natural gas and the unit will operate up to 8760 hours per year, of which no more than 1000 represent fuel oil operation. Emission increases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), volatile organic compounds (VOC), sulfuric acid mist (SAM) and nitrogen oxides (NO_X).

Emission increases of NO_X, SO_2, VOC, SAM and PM will be less than their respective significant emission levels per Table 62-212.400-2, F.A.C. and do not require PSD or non-attainment new source review. PSD review is required for CO and PM_{10} because emissions will increase by more than their respective significant emissions levels.

Unit CC-1 annual NO_X emissions will be limited by the credit from the Unit 8 boiler shutdown and an emission cap that will be rolled monthly and confirmed by a Continuous Monitoring System (CEMS).

4. PROCESS DESCRIPTION AND SELECTED COMBUSTION TURBINE

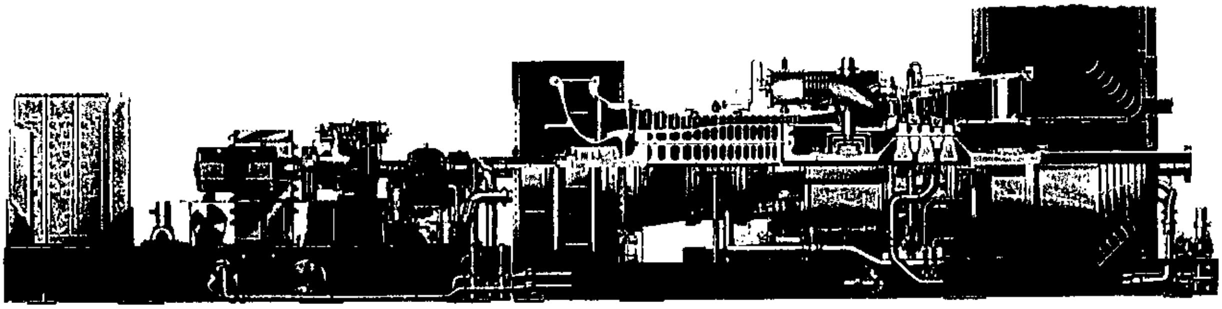
A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the a compressor where it is compressed to a pressure ratio on the order of 10-30:1 depending on the unit. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2000 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

GRU plans to purchase a dual fuel nominal 83 MW General Electric 7EA combined cycle gas turbine with an unfired heat recovery steam generator (HRSG) and utilize the existing Unit No. 8 steam turbine-electrical generator to produce an additional 40-50 MW of electrical power.

An interior view of the GE 7E (a predecessor of the PG 7121EA) and an exterior view of the GE 7EA are shown in Figure 5. The GE 7EA has a 17 stage compressor that achieves a pressure ratio of approximately 12.8 to 1 and will be equipped with DLN combustors.

The GE 7EA is a "heavy duty gas turbine."[1] For reference, the larger GE 7FA and Westinghouse 501F turbines are rated at approximately 170 MW and are thus about twice the size of the 7EA. The latter units represent the largest units presently in commercial service in the United States.



GENERATION COMBUSTION

COMPRESSION EXPANSION

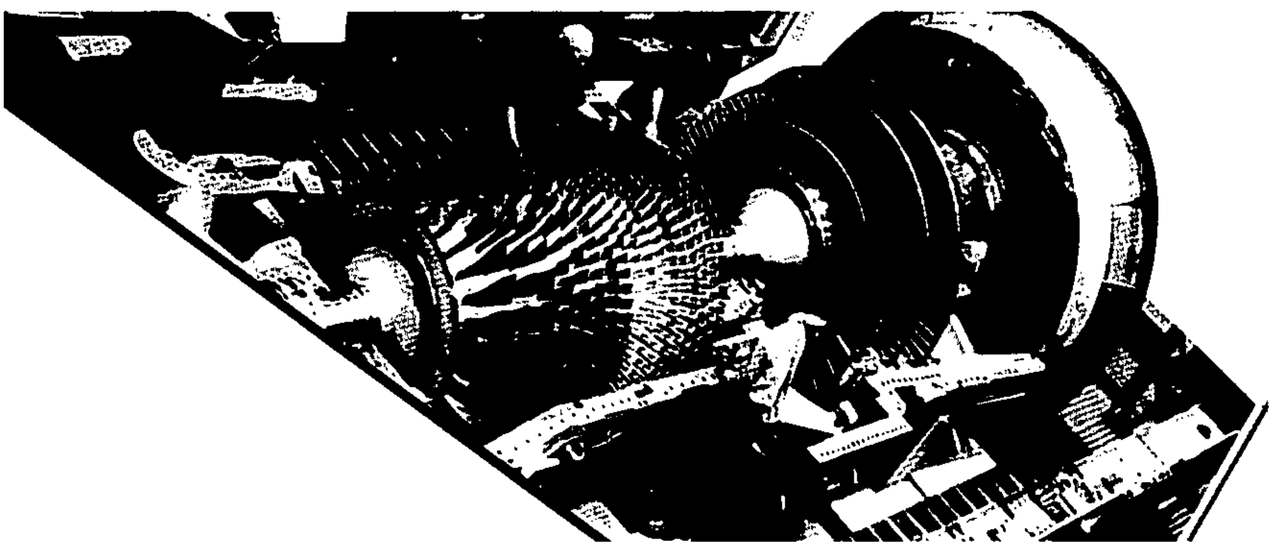


Figure 5 – Internal Diagram and View of GE 7E/EA

The 7EA has a firing temperature of over 2000 °F, a simple cycle efficiency of roughly 33 percent, and a combined cycle efficiency of about 50 percent. In contrast, the 7FA has a firing temperature of 2400 °F and a combined cycle efficiency of 56 percent. Because of the lower firing temperature, the 7EA achieved single digit NO_X emissions sooner and with less technological obstacles than the larger models.

In the GRU project. the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The steam is then fed to a separate steam turbine which also drives an electrical generator. Figure 6 is a process flow diagram for combined cycle operation. GRU expects to operate the unit in simple cycle mode during periods when the HRSG is not operational or when electrical demand makes it uneconomical to operate the HRSG. The bypass stack is used when the unit operates in simple cycle mode. The main stack following the HRSG is required for combined cycle operation.

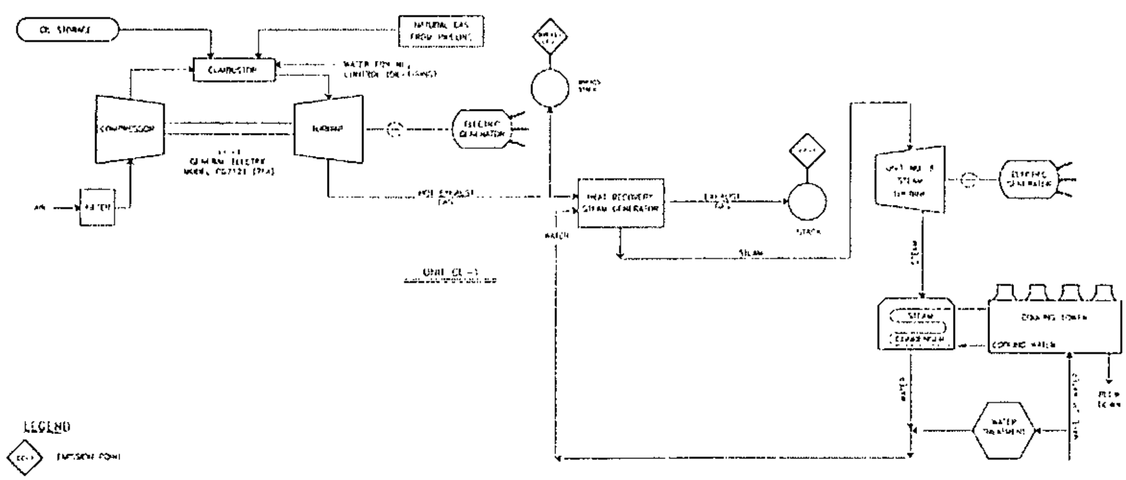


Figure 6 – Process Diagram for Combined Cycle Unit 1

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 10 MW compared to referenced temperatures), an evaporative chiller may be installed ahead of the combustion turbine inlet.

The GE Speedtronic^{TM} Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. Since emissions are controlled utilizing dry low NO_X techniques, fuel staging and combustion mode are also controlled by the Mark V, which also monitors the process. Sequencing of the auxiliaries to allow fully automated start-up, shutdown and cool-down are also handled by the Mark V.[2]

5. NON-BACT CONTROL TECHNOLOGY

A discussion of control technologies for CO and PM_{10} is given in the draft Best Available Control Technology determination accompanying this document. This section describes only the selected control technology for non-PSD (non-BACT) pollutants, including NO_X, VOC, SO_2 and SAM.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas its use is proposed by GRU at 1000 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the proposed GRU turbine. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques for GRU Project

During fuel oil firing, GRU will rely on injection of either water or steam directly into the combustor to lower the flame temperature and thus reduce thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

During natural gas operation, GRU will rely on combustion controls in the form of lean pre-mixed fuel combustion. The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 7 for the General Electric DLN-1 can-annular combustor similar to the model to be used in the GRU project. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal

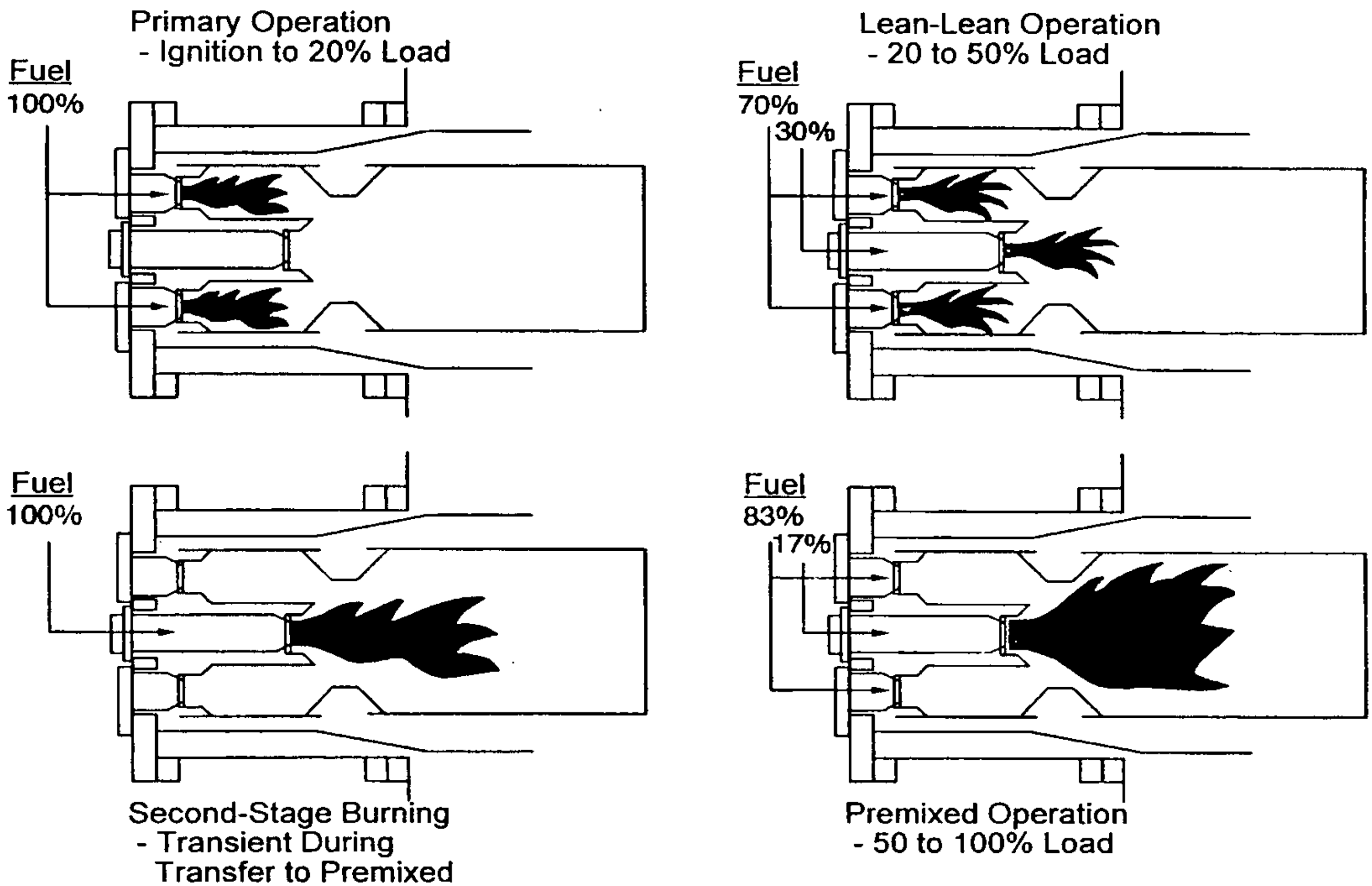


Figure 7 – Fuel-Staged Dry Low NO_x Operating Modes

flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration. At this stage the unit is considered to be in full pre-mix and emissions are controlled.

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the USEPA's NSPS of 75 ppmvd at 15% O_2. GE's first DLN-1 system was tested both on oil and gas at Houston Lighting & Power in 1980 and met its emissions requirements.[3] A prototype DLN-1 system was later tested on a GE 7E combustion turbine at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward.

During the early 1990s the DLN-1 was guaranteed to achieve less than 25 ppmvd NO_X on a GE 7EA combustion turbine. By the mid-1990's this model was guaranteed to achieve 9 ppmvd NO_X. As of 1996 several models such as the 6E, 7E, 6B, 7E, 7B-E, 7EA, 9E, 5P and 3J were DLN-1 equipped machines which achieved single-digit NO_X emissions in all cases. These units are smaller and have lower firing temperatures than the so-called F Class units such as the 170 MW GE 7FA or the Westinghouse 501F.

A cross section of a DLN-1 combustor is shown in Figure 8. This model has been progressively improved since its introduction. The emission characteristics of the an older version (25 ppmvd guarantee) of the DLN-1 combustor while firing natural gas are given in Figure 9. Characteristics while firing fuel oil are shown in Figure 10.

The high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 11 which is from a General Electric discussion on these principles.

The first GE 7EA project in Florida was at the Kissimmee Utilities Cane Island plant in 1993 followed by Polk Power Partners Mulberry Cogen in 1994 and GRU Deerhaven Station in 1995. These units were equipped with earlier versions of DLN-1 combustors to meet a permitted NO_X limit of 15 ppmvd O_2. All are currently operating and actually achieve emissions in the range of 7-11 ppmvd for NO_X. The Department recently issued a permit to TECO for a simple cycle GE 7EA combustion turbine with a permit limit of 9 ppmvd.[4] A draft permit was issued to FPC for three identical units, all of which have proposed permit limits of 9 ppmvd of NO_X.[5]

The requested 9/42 ppmvd NO_X limit on natural gas/fuel oil during baseload and operating in the simple or combined cycle mode is typical compared with some recent BACT determinations for E and F Class units.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Alachua County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD), because the

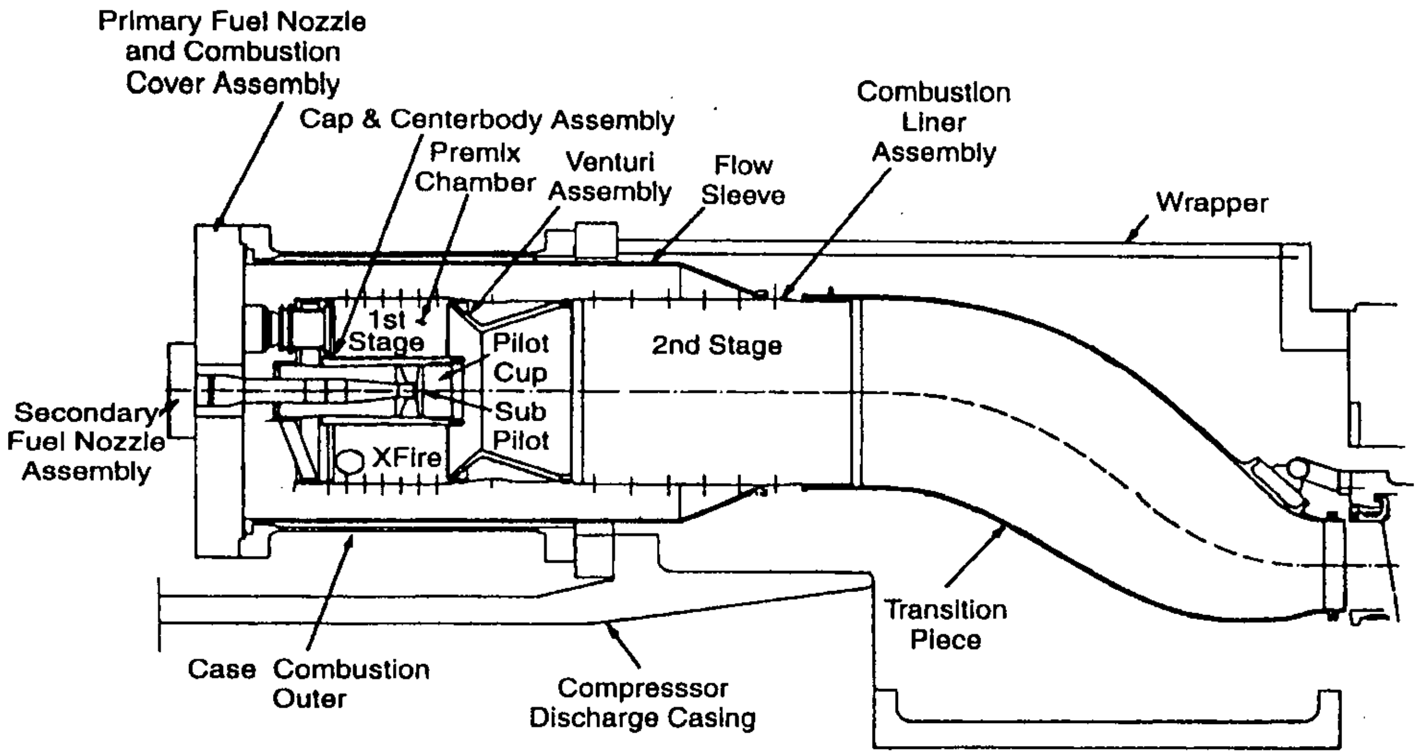


Figure 8 – Cross Section of GE 7EA Dry Low NO_x Combustion System

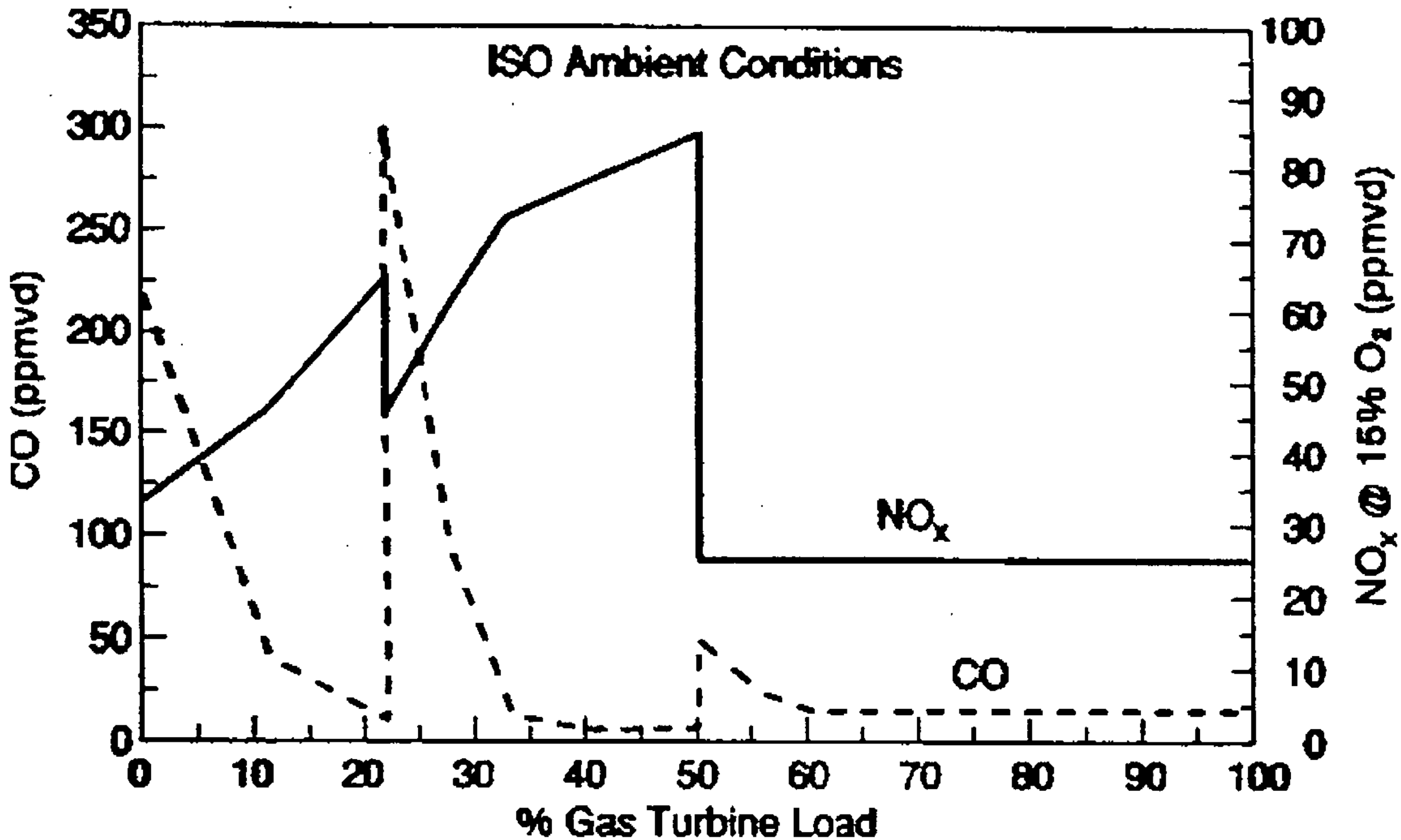


Figure 9 – GE 7EA DLN-1 Combustion System Performance on Natural Gas Fuel

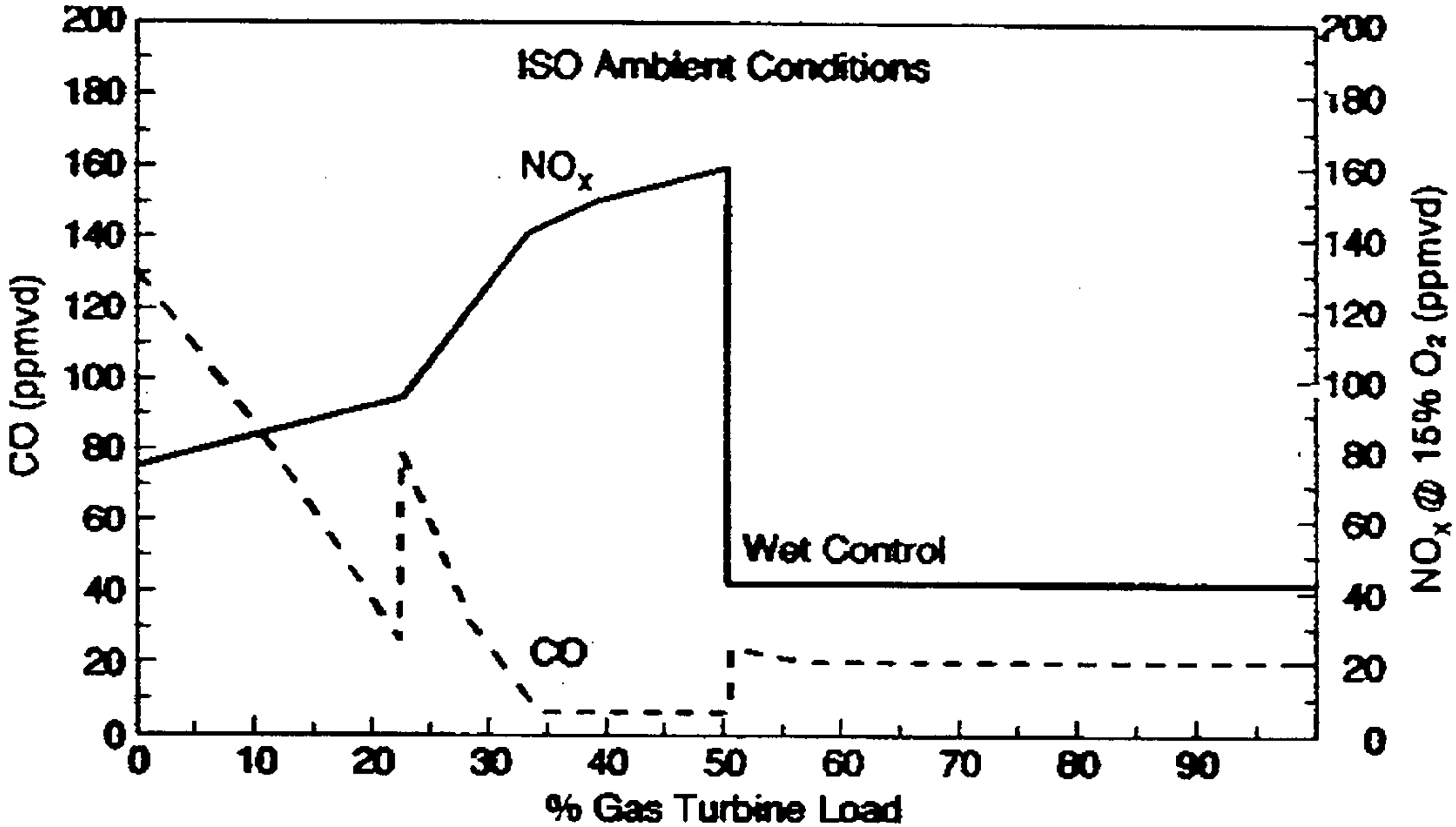


Figure 10 – GE 7EA DLN-1 Combustion System Performance on Distillate Oil Fuel

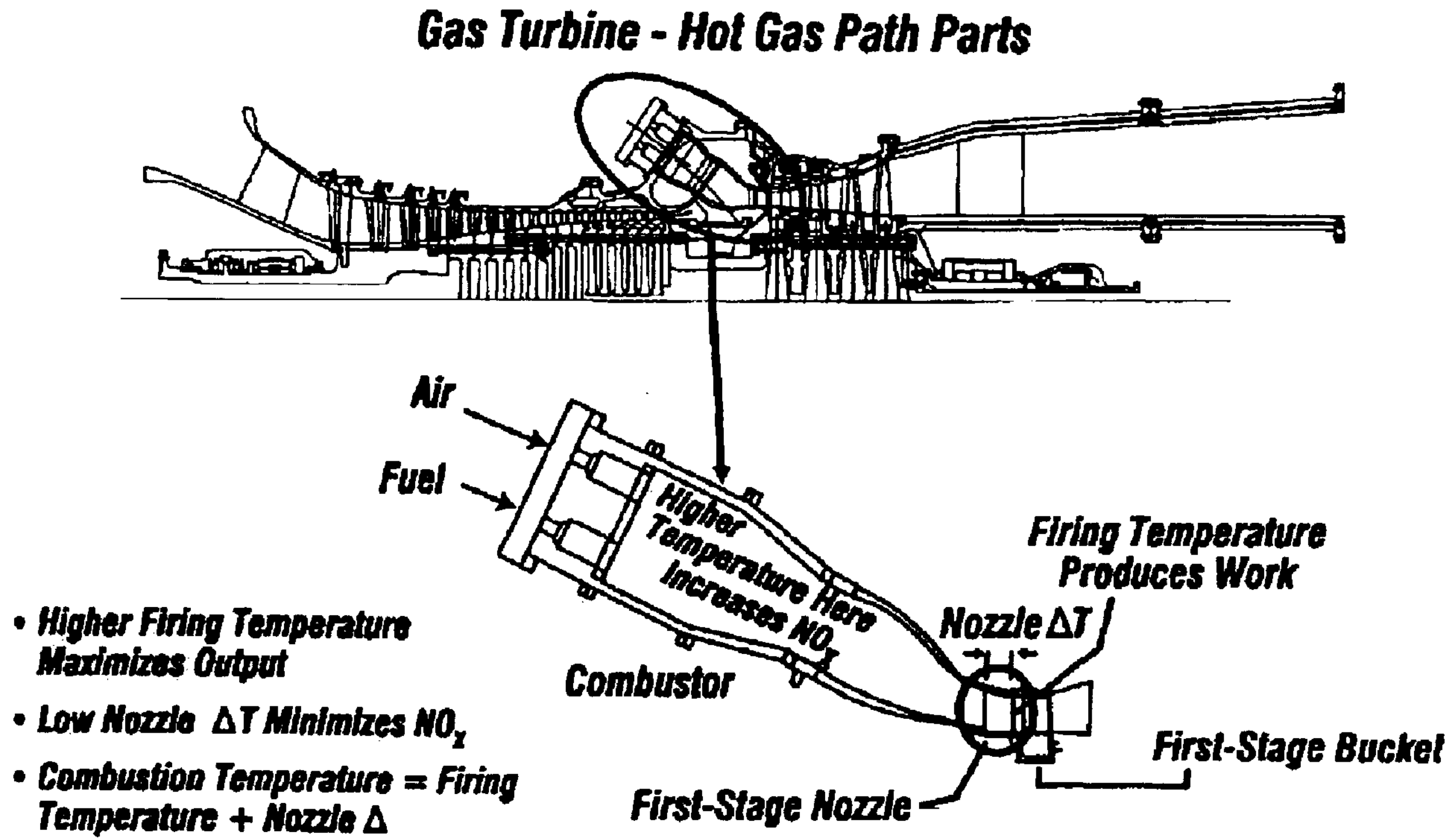


Figure 11 – Relation Between Flame Temperature and Firing Temperature

potential emission increases for PM_{10} and CO exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for PM_{10} and CO. An analysis of the air quality impact from the proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth.

The emission units affected by this PSD permit shall comply with all applicable provisions of the Florida Administrative Code (including applicable portions of the Code of Federal Regulations incorporated therein) and, specifically, the following Chapters and Rules:

5.1 State Regulations

This project is subject to the applicable environmental laws specified in Section 403 of the Florida Statutes (F.S.). The Florida Statutes authorize the Department of Environmental Protection to establish rules and regulations regarding air quality as part of the Florida Administrative Code (F.A.C.). This project is subject to the following applicable requirements of the rules and regulations of the Florida Administrative Code as follows:

Chapter 62-4	Permitting Requirements
Chapter 62-204	Ambient Air Quality Protection and Standards, PSD Increments, and Federal Regulations Adopted by Reference
Chapter 62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
Chapter 62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
Chapter 62-213	Operation Permits for Major Sources of Air Pollution
Chapter 62-214	Acid Rain Program Requirements
Chapter 62-296	Emission Limiting Standards
Chapter 62-297	Test Requirements, Test Methods, Supplementary Test Procedures, Capture Efficiency Test Procedures, Continuous Emissions Monitoring Specifications, and Alternate Sampling Procedures

5.2 Federal Rules

40 CFR 60	NSPS Subpart GG
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, and negligible quantities of sulfuric acid mist (SAM), mercury (Hg) and lead (Pb). The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review. The Department's proposed permitted allowable emissions for these Units are summarized in the Draft BACT document and Specific Conditions Nos. 16 through 21 of Draft Permit PSD-FL-276.

6.2 Emission Summary

PSD review is required for PM_{10} and CO. There will not be significant increases for NO_X, SO_2, SAM, PM and VOC emissions. The maximum potential emissions in tons per year for Unit CC-1 are summarized below for comparison with recent past annual emissions from Unit 8 slated for retirement. All units are in tons per year.

FACILITY EMISSIONS (TPY) AND PSD APPLICABILITY

Pollutant	Unit 8 (potential)	Unit 8 (past)	Unit CC-1 (future)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25 No
PM_{10}	296	1.8	24.4	22.6	**15 Yes**
SAM	160	1.3	5.4	4.1	7 No
SO_2	6,498	29	47.1	18	40 No
NO_x	1,050	94	133 (cap)	39	40 No
VOC	12	2	9.2	7	40 No
CO	78	18	231 (yr 1)	213 (yr 1)	**100 Yes**
CO	78	18	189 (yr 2+)	171 (yr 2+)	**100 Yes**

6.3 Air Quality Analysis

6.3.1 Introduction

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: PM_{10}, and CO. PM_{10} is a criteria pollutant and has national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it.

The applicant's initial PM_{10}, CO, and NO_X air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment analyses for these pollutants were not required. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10} and CO; and
- An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts.

Based on these required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or significantly contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A more detailed discussion of the required analyses follows.

6.3.2 Models and Meteorological Data Used in the Significant Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Gainesville, Florida (surface data) and Waycross, Georgia (upper air data). The 5-year period of meteorological data was from 1984 through 1988. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.3.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the ISCST3 model was used in a screening mode to evaluate dispersion of emissions from the combined cycle facility for three loads (60%, 80% and 100%) and three seasonal operating conditions (summer, winter, and average). Once the worst-case loads are identified, the applicant utilizes the ISCST3 model to evaluate impacts at these loads, and compares the results to the significant impact levels. If this modeling at worst load conditions shows significant impacts, additional multi-facility modeling is required to determine the project's impacts on existing air quality and any applicable AAQS or PSD increments.

Receptors were placed around the facility, which is located in a PSD Class II area. They were also placed in the Okefenokee (ONWA) and Chassahowitzka (CNWA) National Wilderness Areas, which are the closest PSD Class I areas. The ONWA and CNWA are located approximately 102 km north and 103 km southwest of the project, respectively. A combination of fence line, near-field, mid-field, and far-field receptors were utilized for predicting maximum concentrations in the vicinity of the project. The fence line and near-field receptors consisted of discrete Cartesian receptors spaced at 50 meter intervals from the facility fence line out to the first mid-field polar receptor ring. The mid-field and far-field receptors consisted of polar receptor grids with 10 rings and 10° spacing radials. To improve the spatial distribution of the polar receptors, each polar ring was offset by 5°. For predicting impacts at the ONWA and CNWA, discrete receptors were placed along the borders of the PSD Class I areas. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the PSD Class I areas. The tables below show the results of the significant impact modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.04	1	NO
	24-hour	2.1	5	NO
CO	8-hour	8.3	500	NO
	1-hour	43.1	2000	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (ONWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0004	0.2	NO
	24-hour	0.02	0.3	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0006	0.2	NO
	24-hour	0.02	0.3	NO

The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.3.4 Impacts Analysis

Impact Analysis Impacts On Soils, Vegetation, And Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant generating equal power. Emission increases of acid rain and ozone precursors will be less than the significant emission rates. Therefore PSD review is required only for PM_{10} and CO.

The maximum ground-level concentrations predicted to occur for PM_{10}, and CO, (and SO_2 and NO_X) as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels which in-turn are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize PM/PM_{10} generation and smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. Due to the distance of the source from the ONWA and CNWA PSD Class I Areas, plus the type and amount of emissions from the source, the U.S. Fish and Wildlife Service believes that there is a low potential for visibility impacts. Therefore, no regional haze analysis was required for this project.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require few if any new permanent employees, which will cause no significant impact on the local area.

The Public Service Commission has determined that power projects are needed to meet the low electrical reserve capacity throughout the State of Florida. The project is a response to local demand, state-wide and regional growth, and will accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint," low water requirements, and the among the lowest air emissions per unit of electric power generating capacity for intermittent duty. Furthermore, the repowering project will results in the shutdown of an old boiler that would otherwise emit more pollution and produce less electricity if operated to meet future demand.

Hazardous Air Pollutants

The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any specific industry or HAP control requirements pursuant to Section 112 of the Clean Air Act.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. Furthermore, it will replace a unit that has a potential to emit of about 8,000 tons per year of regulated pollutants with a unit that is limited to about 400 tons per year and which can produce nearly three times as much power.

A. A. Linero, P.E.
Teresa Heron, Engineer
Chris Carlson, Meteorologist

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APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM_{10}) and carbon monoxide (CO). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical generator to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a 100 foot stack for combined cycle operation, and a 78 foot bypass stack for simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs) 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppmvd (gas – after 1st yr) 20 ppmvd (fuel oil)

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (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. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). There are no limits for CO or PM_{10} in Subpart GG. PSD was not triggered and a BACT determination is not required for NO_X or SO_2. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY STATES:

The following table is a sample of information on recent CO and PM_{10} BACT or emission limits set by Florida and Southeastern States for General Electric 7EA combustion turbines. The GRU project is included for comparison. The first two projects are for simple cycle installations.

Project Location	CO - ppmvd (or lb/mmBtu)	PM - lb/hr (and/or % opacity)	Technology	Comments
FPC Int. City, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	3x87 MW GE 7EA 12/99 1000 hrs oil
TECO Hardee, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	One 75 MW GE 7EA. 10/99 1000 hrs oil
Olin Cogen, AL	0.07 lb.mmBtu - NG (equals ~ 29 ppmvd))		Clean Fuels Good Combustion	One 80 MW GE 7EA 12/97 DB & PA
GE Plastics Cogen, AL	0.08 lb.mmBtu - NG (equals ~ 33 ppmvd)		Clean Fuels Good Combustion	One 80 MW GE 7EA 5/98 Duct Burner
GRU Gainesville, FL	20 – NG or FO 25 – NG 1st year	5/10 lb/hr - NG/FO 10 percent Opacity	Clean Fuels Good Combustion	One 83 MW GE 7EA Repower 1000 hrs oil

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and (per the application) will be used for a maximum of 1000 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical. Annual emissions of PM_{10} are expected to be less than 24.4 tons.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[1]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations are typically permitted to achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. GRU proposes to meet a limit of 20 ppmvd while firing natural gas or fuel oil. GRU requests that it be allowed to initially meet a limit of 25 ppmvd when firing natural gas and to achieve 20 ppmvd after one year. The reason is that GE only offers a guarantee of 25 ppmvd for natural gas on a 7EA unit.

Although GE does not offer a single digit CO guarantee on the 7EA, according to its own reports, CO single-digit emissions have been achieved simultaneously with single-digit NO_X emissions on several MS7001EAs.[2] When the same units are operated at peak power, "expected" CO emissions are 6 ppmvd with an increase of NO_X to 18 ppmvd.

According to recent data reviewed by the Department, actual CO emissions from eight 7E units undergoing conversions to 7EA and DLN-1 technology achieved between 1.3 and 10.5 ppmvd of CO with an average of 5 ppmvd.[3] This was accomplished while the units achieved single-digit NO_X values. The Department expects similar actual performance from the GRU project.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the GRU project assuming full load.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM_{10}, VE	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas) 10 lb/hr (oil, 1000 hrs)) 10 Percent Opacity
CO	Combustion Controls	25 ppmvd and 54 lb/hr (gas – 1st year) 20 ppmvd and 43 lb/hr (gas – after 1st year) 20 ppmvd and 43 lb/hr (fuel oil)

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The top technology in a top/down analysis for PM_{10} control is good combustion control of inherently clean fuels. No further control methods are available.
- The values of 5 pounds per hour while burning natural gas and 10 lb/hr while burning fuel oil reflect BACT when coupled with a visible emissions limit of 10 percent opacity. The higher 10 lb/hr rate is limited by allowing only 1000 hours of back-up fuel oil use. Most years, fuel oil use will be substantially less than 1000 hours.
- The top technology in a top/down analysis for CO is installation of oxidation catalyst. Use of oxidation catalyst is not widespread except in CO non-attainment areas. It is used in attainment areas when a unit is used that has inherently high emissions of CO.
- GRU's consultant evaluated the use of an oxidation catalyst for the Unit 8 repowering project. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.

- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	Method 10 (can use RATA if at capacity)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

Date:

REFERENCES

[1] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[2] Paper. Davis, L.B., GE. Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines. 1998.

[3] Paper. Ihfe, L.M., et. al., Texaco P&G. Kern River and Sycamore Cogen Plant Uprates and Emission Compliance. Power-Gen Conference. New Orleans, Louisiana. November 30, 1999.

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 100 foot stack for combined cycle operation; a 78 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

STATEMENT OF BASIS:

This Air Construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 7 and 8 have nameplate ratings of 25 and 50 MW respectively.

Unit No.8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One nominal dual fuel 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

This project is not subject to the requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ______ 1999
- Department's Final Determination and BACT determination issued with this Final Permit.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION II - ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility as defined in Rule 62-210.200 F.A.C.. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. Construction Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 40 CFR 52.21(r)(2)]

7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation 30 days prior to the expiration of the permit (Rule 62-4.080, F.A.C.).

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

10. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department's Northeast District Office. [Chapter 62-213, F.A.C.]

11. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

12. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's Northeast District and Northeast District Branch Offices by March 1st of each year.

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3) , Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, excess as otherwise specified herein (See Condition 39). Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   40CFR60.7, Notification and Recordkeeping
   40CFR60.8, Performance Tests
   40CFR60.11, Compliance with Standards and Maintenance Requirements
   40CFR60.12, Circumvention
   40CFR60.13, Monitoring Requirements
   40CFR60.19, General Notification and Reporting requirements

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide and particulate matter smaller than 10 microns..

4. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

GENERAL OPERATION REQUIREMENTS

5. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

6. Combustion Turbine Capacity: The maximum heat input rates, based on the Higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

7. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

8. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the owner or operator shall notify the DEP Northeast District Office and Northeast District Branch Office as soon as possible, but at least within (1) working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; the steps being taken to correct the problem and prevent future recurrence; and where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit and the regulations. [Rule 62-4.130, F.A.C.]

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 and 62-210.650, F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for each unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070, and 62-210.650, F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NO_X, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO, NO_X, and VOC emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.]

14. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

EMISSION LIMITS AND STANDARDS

15. Nitrogen Oxides (NO_X) Emissions:
    - Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 30-day rolling average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]
    - Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 3-hour rolling average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]
    - Emission Cap. Total emissions of NO_X shall not exceed 133 tons on a consecutive 365 day basis, rolled daily. Compliance will be demonstrated by the CEMS. [Applicant Request, Rule 62-4.070, F.A.C., escape PSD requirements of Rule 62-212.400, F.A.C.]
16. Carbon Monoxide (CO) Emissions:
    - Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd. Emissions of CO shall not exceed 54 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
    - Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed 43 lb/hr (at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]
18. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable NSPS SO_2. [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]
19. Particulate Matter (PM/PM_{10}) PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for PM/PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]
20. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except as follows:

- During "cold start-up" to combined cycle plant operation up to four hours of excess emissions are allowed.
- During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed.
- Unless authorized by the Department.

Excess emissions are defined as one-hour periods when NOx emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours. NO_X CEM data shall be recorded and included in calculating the NO_X emissions cap. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

23. Compliance Time: Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate for each fuel, but not later than 180 days of initial start up on each fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change of combustors. Year two (YR2) compliance testing for CO shall be performed in the second year of operation. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

    - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (YR2 gas only, I and A).
    - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG. Test data shall be corrected to ISO conditions.

- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. Continuous Compliance with the NO_X Emission Limits:

- Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 30-day rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 30 days. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

- Compliance with the NO_X emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

- A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C.

- Periods when the 30-day rolling average (gas), 3-hr average (oil) or the 365 day rolling average NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Continuous Compliance with the NO_X Emission Cap: NO_X data collected by the CEMS shall be used to demonstrate compliance with the 365-day rolling NO_X emissions cap for each calendar day of operation by the following method:

- For each hour of operation (including startup and shutdown), the NO_X CEMS shall calculate and record the hourly NO_X emissions in units of pounds per hour, rounded to the nearest tenth of a pound. Each hourly emissions rate shall be calculated using at least two valid data points at least 15 minutes apart.

- For each calendar day of operation, the NO_X CEMS shall calculate and record the daily NOx emissions in units of pounds per day, rounded to the nearest tenth of a pound. Daily emissions rates shall be the sum of all recorded hourly emissions rates.

- For each calendar day of operation, the NO_X CEMS shall calculate and record the 365-day rolling total in units of tons, rounded to the nearest hundredth of a ton. The 365-day rolling total shall be the sum of all recorded daily NO_X emissions rates for the applicable 365 consecutive day period. NO_X emissions shall be recorded as "zero" for any days occurring prior to initial startup of the combustion turbine. [Rule 62-4.070(3), F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

27. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas; is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40

CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

28. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted.

29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted.

    Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

32. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

33. Test Results: Compliance test results shall be submitted to the DEP's Northeast District and Northeast District Branch Offices no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

35. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 39) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 through 17. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (version)].

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The CEMS NOx shall be used to determine periods of excess emissions. One-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas and fuel oil, respectively shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when short-term NO_X emissions [i.e., 30-day rolling average (gas) and 3-hour average (oil) or the annual total (i.e., 365-day rolling average) are above the emission limitations listed in Specific Condition No 15, shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (version)].

40. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

41. <u>CEMS Certification and Quality Assurance Requirements:</u> The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

42. <u>Custom Fuel Monitoring Schedule (Natural Gas):</u> Subject to EPA approval, monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meet the definitions (40CFR 72). A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:
    - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
    - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of natural gas or pipeline supplied natural gas.
    - SO_2 emissions shall be monitored using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
    - This custom fuel monitoring schedule will only be valid when natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

43. <u>Custom Fuel Oil Monitoring Schedule</u>: Subject to EPA approval, the following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

44. <u>Determination of Process Variables:</u>
    - The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    - Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, pressure gauges, etc., shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C].

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology for CO and PM_{10} (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy

FROM: A. A. Linero AAL 12/16

DATE: December 16, 1999

SUBJECT: Gainesville Regional Utilities (GRU)
J.R. Kelly Generating Station (0010005-002-AC, PSD-FL-276)

Attached is the public notice package for construction of a nominal 133 MW GE 7EA combined cycle unit that will operate in conjunction with the existing Unit No. 8 steam turbine-electrical generator. The existing Unit 8 boiler will be shut down.

A PSD review and BACT determination was performed for CO and PM_{10}. Both of these pollutants will be controlled by good combustion of clean fuels. A cap on NO_X emissions of 133 tons on a 365 day basis rolled daily is included to insure that PSD is not triggered for this pollutant. This reflects the 94 tons credit for the shutdown of the Unit 8 boiler. Additionally NO_X emissions while firing natural gas will be limited to 9 ppmvd at 15 percent O_2 on a 30-day rolling average. Fuel oil may be used up to 1000 hours per year during which emissions of 42 ppmvd are allowed.

During a "typical year" there will be no effect on GRU's operation of the unit. If the unit operates at a very high capacity factor and uses a lot of fuel oil, then the cap can become restrictive. GRU supplied a letter to revise the application and request the cap. The project will result in a total reduction of about 7,500 in allowable emissions of regulated pollutants and a nearly three-fold increase in maximum power capacity.

I recommend your approval of the attached Intent to Issue.

AAL/aal

Attachments

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

P.E. Certification Statement

Permittee: **DEP File No.** 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities (GRU)
Gainesville, Alachua County

Project type:

Project will be at the GRU J.R. Kelly Generating Station near Downtown Gainesville, Alachua County. Project is construction of a nominal 83 megawatt (MW) GE PG7121EA, gas and oil-fired, combined cycle combustion turbine with a supplementary-fired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 40-50 MW via an existing steam-driven electrical generator. Project also includes: a 100-foot stack, a 78-foot stack for simple cycle operation; a cooling tower for pond water (existing) and a small heater to heat the natural gas prior to use in simple cycle operation.

Nitrogen oxides (NO_X) limits are 9 ppmvd @15% O_2 (30-day average) for gas firing achievable by Dry Low NO_X and 42 ppmvd (3-hour average) for oil firing by wet injection. Other pollutants, including PM/PM_{10}, CO, VOC, H_2SO_4, and SO_2 will be controlled by good combustion and use of clean fuels.

Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I (Chassahowitzka and Okeefenokee) National Wilderness Areas) and Class II areas.

***I HEREBY CERTIFY** that the engineering features described in the above referenced application and subject to the proposed permit conditions provide reasonable assurance of compliance with applicable provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 62-4 and 62-204 through 62-297. However, I have not evaluated and I do not certify aspects of the proposal outside of my area of expertise (including but not limited to the electrical, mechanical, structural, hydrological, and geological features).*

12/16/99

A A. Linero, P.E. Date
Registration Number: 26032

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
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Tallahassee, Florida 32301
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