Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 30, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ms. Roxane Kennedy, Plant General Manager
FPL Sanford Plant
950 South Highway 17-92
DeBary, Florida 32713

Re: DEP File No. 1270009-004-AC, PSD-FL-270
FPL Sanford Plant - 2200 MW Gas Repowering Project

Dear Ms. Kennedy,

Enclosed is one copy of the Intent to Issue, Draft Air Construction Permit, and Technical Evaluation and Preliminary Determination for the referenced project at the FPL Sanford Plant, 950 South Highway 17-92, DeBary, Volusia 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 OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT" must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to the requirements of 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 other questions, please call Ms. Teresa Heron at 850/921-9529.

Sincerely,

A A Linero 7/30.

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

CHF/th

Enclosures

In the Matter of an
Application for Permit by:

Ms. Roxane Kennedy, Plant General Manager
FPL Sanford Plant
950 South Highway 17-92
DeBary, Florida 32713

DEP File No. 1270009-004-AC
PSD-FL-270
2200 MW Gas Repowering Project
Volusia County

INTENT TO ISSUE AIR CONSTRUCTION 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, Florida Power & Light Company (FPL), applied on June 15,1999 to the Department to install eight (8) combined cycle units and auxiliary equipment to replace two (2) residual oil and gas-fired steam generators at the Sanford Plant near DeBary, Volusia 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 is required to conduct the 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. 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permit. 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). The Department suggests that you publish the notice within thirty days of receipt of this letter. 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 or other authorization. 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 and requests for a public hearing (meeting) concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "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 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, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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.

AA Linero, P.E.

for 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, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7-30-99 to the person(s) listed:

Roxane Kennedy, FPL*
Richard Piper, FPL
Len Kozlov, DEP CD
Gregg Worley, EPA
John Bunyak, NPS
Ken Kosky, P.E., Golder Associates
Peter Cunningham, Esq., HGSS

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.

Kori Fober 7-30-99
(Clerk) (Date)

Z 333 618 117

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to Royane Kennedy	
Street & Number FPL + Sanford	
Post Office, State, & ZIP Code DeBary 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	7-30-99

PS Form 3800, April 1995

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- 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.

I also wish to receive the following services (for an extra fee):

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

Consult postmaster for fee.

3. Article Addressed to:
Ms Royane Kennedy
Fla. Power + Light - Sanford
950 S. Highway 17-92
DeBary, Fl 32713

4a. Article Number
Z 333 618 117

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

7. Date of Delivery

DEBARY AUG 2 5 1999 USPS - 32713

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X Dale G. Dyke

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt

Thank you for using Return Receipt Service.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1270009-004-AC
PSD-FL-270
Florida Power & Light Sanford Plant
2200 Megawatt Repowering Project
Volusia County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Florida Power & Light Company (FPL). The permit is to install eight combined cycle units to replace two (2) residual oil and gas-fired steam generators at the Sanford Plant near DeBary, Volusia County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. for only emissions of volatile organic compounds (VOCs). The applicant's name and address are Florida Power & Light, Sanford Plant, 950 South Highway 17-92, DeBary, Florida 32713.

Each unit is a nominal 170 megawatt General Electric PG7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce approximately another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with existing residual oil and gas-fired Units 4 and 5 (872 MW total capacity) will be dismantled. Existing residual oil and gas-fired Unit 3 will be retained including its stack and boiler. Distillate oil will be used as back up fuel on four of the gas turbines and limited to an aggregate of 500 hours per year per turbine. The four other gas turbines will fire only natural gas but will be able to operate in simple cycle (non-steam mode). The project also includes: a cooling tower for pond water; small heaters to heat the natural gas prior to use in simple-cycle operation; and twelve relatively short stacks.

When firing natural gas, nitrogen oxides (NO_x) emissions will be controlled by Dry Low NO_x (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of carbon monoxide (CO) will be controlled to 12 ppm, while emissions of volatile organic compounds (VOC) will be less than 1.4 ppm. Emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the switch to inherently clean pipeline quality natural gas. When firing fuel oil in four of the eight turbines, the NO_x emissions will be limited to 42 ppm at 15% O_2 using water injection. Very low sulfur (0.05 percent) will be used. Emissions of CO and VOC will be controlled to 20 ppm and 7 ppm, respectively when firing fuel oil. The emissions of VOCs from the repowered project have been determined to be BACT.

There will be very substantial decreases in regulated air pollutants except for a small increase in VOC emissions. The maximum potential annual emissions in tons per year are summarized below for comparison with recent annual emissions from Units 4 and 5 slated for retirement.

Pollutants	Units 4/5 Emissions	After Repowering	Increase (decrease)
PM/PM_{10}	538	387/374	(151/164)
SAM	1,276	42.3	(1,234)
SO_2	28,729	279	(28,450)
NO_x	9,984	2,757	(7,227)
VOC	67	124	57
CO	2,906	1,719	(1,188)

The lower NO_x emissions will reduce ozone (smog) formation potential and nitrate fallout. The lower PM/PM_{10}, SO_2 and SAM emissions will reduce visible emissions, fine particulate generation, and acid smut fallout. An air quality impact analysis was conducted. Impacts due to the proposed project emissions are all favorable and the net effect is a "creation of available increment."

The existing 156 MW residual oil and gas-fired Unit 3 will be retained. However its future operation will be limited as a result of plant-wide emissions caps requested by FPL. These proposed caps include the emissions above and are equal to 500 TPY of PM/PM_{10}, 4,500 TPY of NO_X, and 4000 TPY of SO_2. According to EPA's acid rain data, the entire plant emitted 38,660 TPY of SO2 and 16,878 TPY of NO_X in 1998. Absent this repowering project and the proposed plant-wide emissions cap, the permitted emissions from the plant are over 100,000 TPY of SO_2 alone and there is no NO_X limit.

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.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of "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 Sanford Repowering Project is not subject to review under Section 403.506 F.S. (Power Plant Siting Act), because it provides for no expansion in steam generating capacity.

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, as well as the rules and statutes which entitle the petitioner to relief; and (f) A demand for relief.

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.

A complete project file is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Florida Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-1344
Fax: 850/922-6979

Florida Department of Environmental Protection
Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767
Telephone: 407/894-7555
Fax: 407/897-5963

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 904/488-0114, for additional information.

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Florida Power & Light Company

Sanford Power Plant

2200 Megawatt Repowering Project

Volusia County

DEP File No. 1270009-004-AC
PSD-FL-270

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

July 30, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Florida Power & Light Company
Sanford Power Plant
950 South Highway 17-92
DeBary, Florida 32713

Authorized Representative: Roxane Kennedy, Plant General Manager

1.2 Reviewing and Process Schedule

06-15-99:	Date of Receipt of Application
06-15-99	Completeness Date
07-30-99:	Intent Issued

2. FACILITY INFORMATION

2.1 Facility Location

Refer to Figure 1. The Sanford Plant is located in the City of DeBary, Volusia County, on 1,700 acres, west of Highway 17-92 and approximately 3 miles northeast of Sanford. This site is approximately 130 kilometers from Chassahowitzka National Wilderness Area, a Class I PSD Area.

The UTM coordinates of this facility are Zone 17; 468.3 km E; 3,190.3 km N.

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

The Florida Power & Light (FPL) Sanford Plant generates electric power from three residual fuel oil-fired and gas-fired steam units with a combined nominal generating capacity of 1,028 megawatts (MW).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than 40 TPY of NO_x or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. The present modification results in net emissions decreases or less-than-significant increases in PSD pollutants with the exception of VOCs. The modification is subject to PSD for VOCs.

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.

Florida Power & Light Company (FPL) proposes to install eight (8) natural gas-fired combined cycle units that will consist of eight (8) nominal 170 MW (@ 59°F) combustion turbine-generators with heat recovery steam generators (HRSGs). These will replace the existing boilers for Units 4 and 5 at the Sanford Power Plant in Volusia County. The HRSGs will raise steam to repower the existing steam turbines thus producing approximately another 80 MW of electricity per unit or 2,200 MW for the eight combined cycle units. The main components of the combined cycle units are shown in Figure 4.

Each turbine will be equipped with Dry Low NO_x (DLN-2.6) 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. Each turbine will have a nominal heat input of 1,600 million Btus per hour, lower heating value (MMBtu/hr, LHV) at 59°F. The HRSGs will not be supplementally fired and will raise steam only from hot (1,100°F) combustion turbine exhaust. When firing oil, NO_x will be limited to 42 ppmvd at 15% O_2 using water injection.

Internal and external views of the GE MS 7001FA (a predecessor of the MS 7241FA) are shown in Figure 5. Each unit will be delivered with 14 can-annular design, DLN-2.6 combustors instead of the earlier-generation combustors supplied with the MS7001FA.

The project includes a mechanical draft cooling tower to reduce the temperature of the water discharged into the existing cooling pond cooling system. A 60-foot bypass stack will be installed on 4 combustion turbines associated with Unit 4 for simple cycle (non-HRSG) operation. A separate 125-foot stack will also be installed for each combustion turbine for combined cycle operation. A maximum of 176 million Btu per hour (MMBtu/hr) gas-fired direct-fired heaters will be installed as well as 10-foot stacks. These units will be used to heat natural gas prior to simple cycle operation and during cold start-up.

The turbines associated with Unit 4 will initially operate in simple cycle mode until the corresponding HRSG is installed and integrated with the existing steam turbines. The existing stacks and steam generators (boilers) for Units 4 and 5 will be dismantled within one year after complete implementation of combined cycle operation.

The combustion turbines associated with Unit 5 (i.e. 4 CTs) will be equipped to fire very low sulfur (0.05%) distillate oil in the event gas is not available. The use of distillate oil will not exceed an aggregate of 500 hrs/yr per turbine.

Emission decreases will occur for carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4 mist or SAM), particulate matter (PM/PM_{10}), and nitrogen oxides (NO_x). Emission increases of volatile organic compounds (VOC) will be greater than the significant emission levels per Table 62-212.400-2, F.A.C. Therefore, review for the Prevention of Significant Deterioration (PSD) is only required for VOC emissions.

4. PROCESS DESCRIPTION

Much of the following discussion is from a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas turbines.[1] Project specific information is interspersed where appropriate.

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimizes NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °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.

In the FPL project, the unit will operate primarily in combined cycle mode although FPL plans to operate the some of the turbines associated with Unit 4 initially in simple cycle mode. Cycle efficiency, defined as a percentage of useful shaft energy output to fuel energy input, is approximately 35 percent for F-Class combustion turbines in simple cycle mode. In addition to shaft energy output, 1 to 2 percent of fuel input energy can be attributed to mechanical losses. The balance is exhausted from the turbine in the form of heat.

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine that also drives an electrical generator. A bypass stack is used when the unit operates in simple cycle mode. The main stack follow the HRSG and is required for combined cycle operation. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 20 MW compared to referenced temperatures), inlet foggers will be installed ahead of the combustion turbine inlet air intake duct. At an ambient temperature of 95°F, roughly 10 MW of power can be regained by using the foggers.

The FPL project is representative of *gas repowering, which* is characterized by replacement of a conventional fossil fuel-fired steam unit with one or more combustion turbines and HRSGs. Typically, the existing boiler, stack, and fans are removed or abandoned, while the existing steam turbines and related auxiliaries are retained as part of the repowered combined-cycle units.[2] This concept is shown in Figure 6.

The first gas repowering project in Florida was at the FPL Lauderdale Plant. FPL installed four (4) Westinghouse 501 F combustion turbines and HRSGs to replace two conventional units. The steam generators were kept. Summer generating capacity was increased from approximately 275 to 850 MW. Whereas the original units were used primarily as peaking units, the more efficient repowered plant has a high availability more representative of a baseload plant. A photograph of the FPL Lauderdale Plant is shown below.

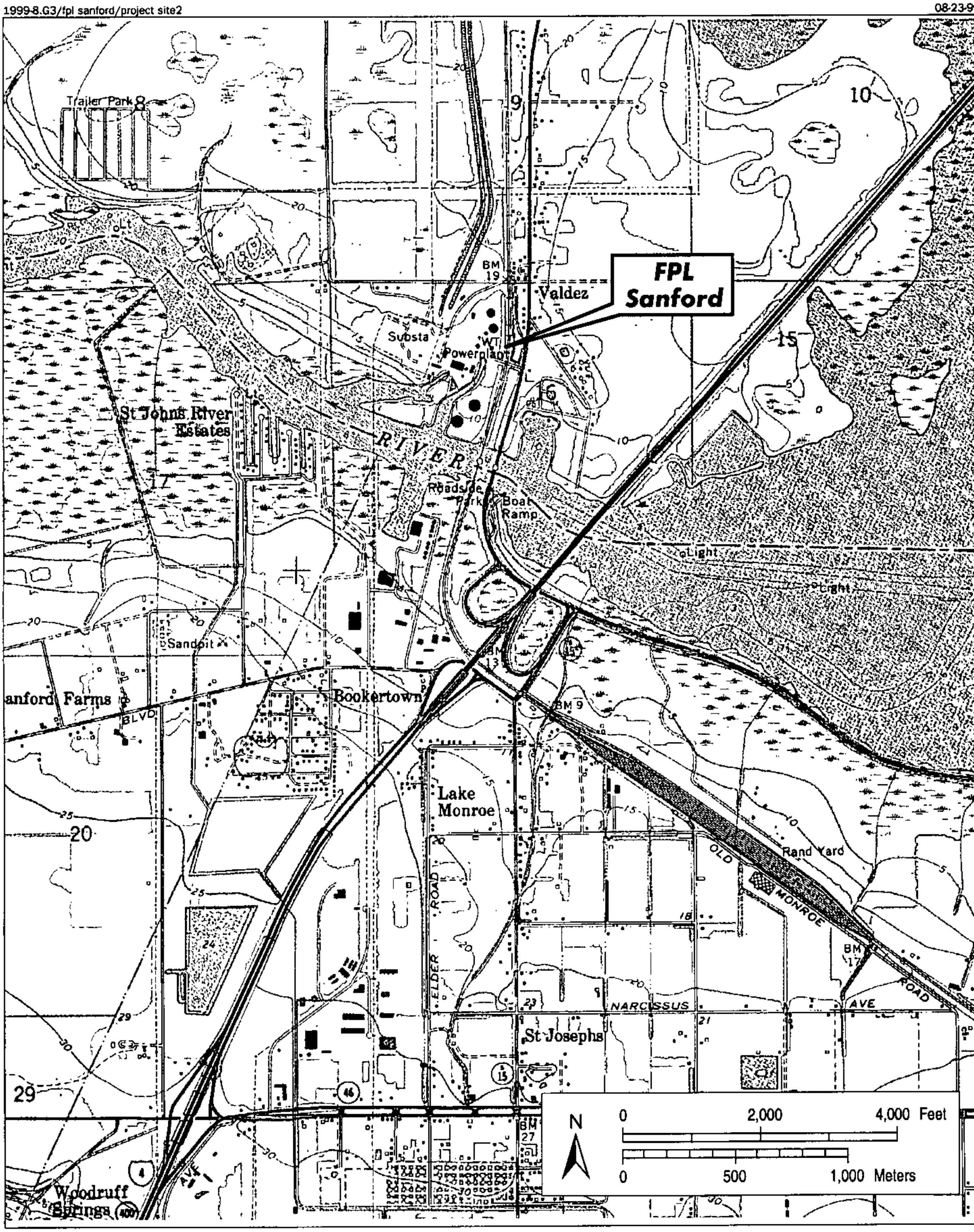


Figure 1
FPL Sanford Plant Location

Sources: USGS, 1988; Golder Associates Inc., 1999.

The location of the Sanford Plant within the FPL grid is shown below:

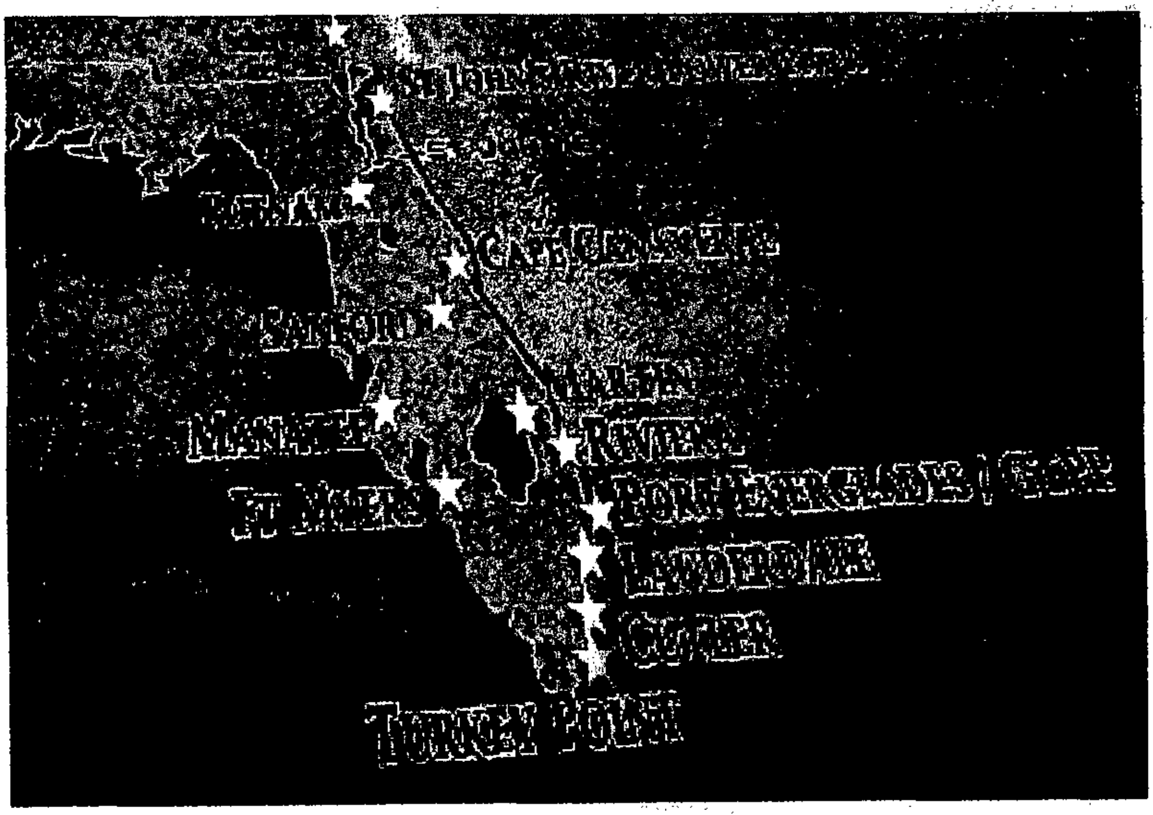


Figure 2 – Location of FPL Facilities in Florida

Figure 3 is an aerial photograph of the plant.

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
004-011	Power Generation	Eight (8) Combined Cycle Combustion Turbine-Generators with Unfired Heat Recovery Steam Generators
012-019	Fuel Heating	Natural Gas Heater(s)
020	Water Cooling	Mechanical Draft Cooling Tower

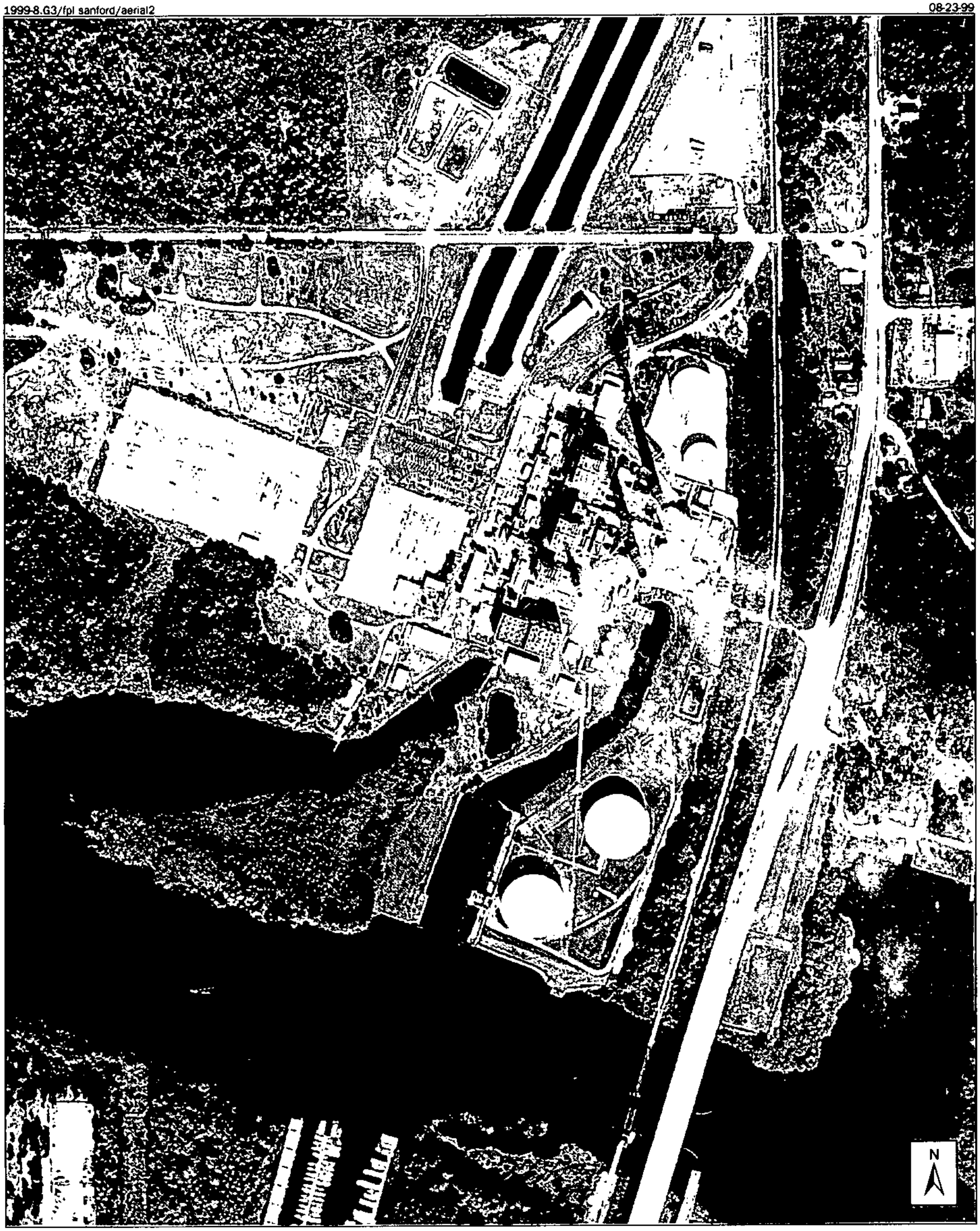


Figure 3
Aerial Photograph of FPL Sanford Plant

Sources: FPL, 1999, Golder Associates Inc., 1999

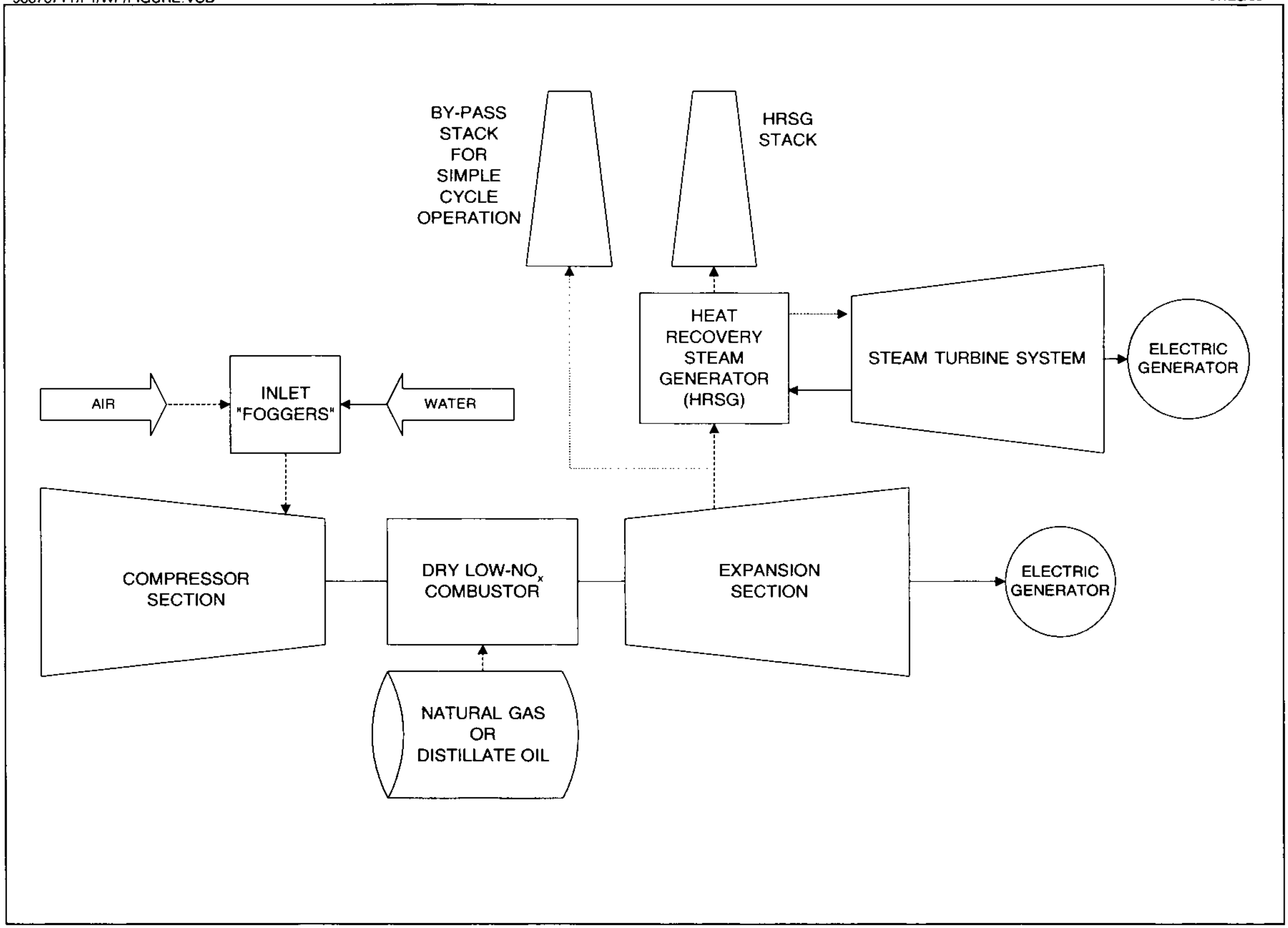


Figure 4. Simplified Flow Diagram of Combined Cycle Operation

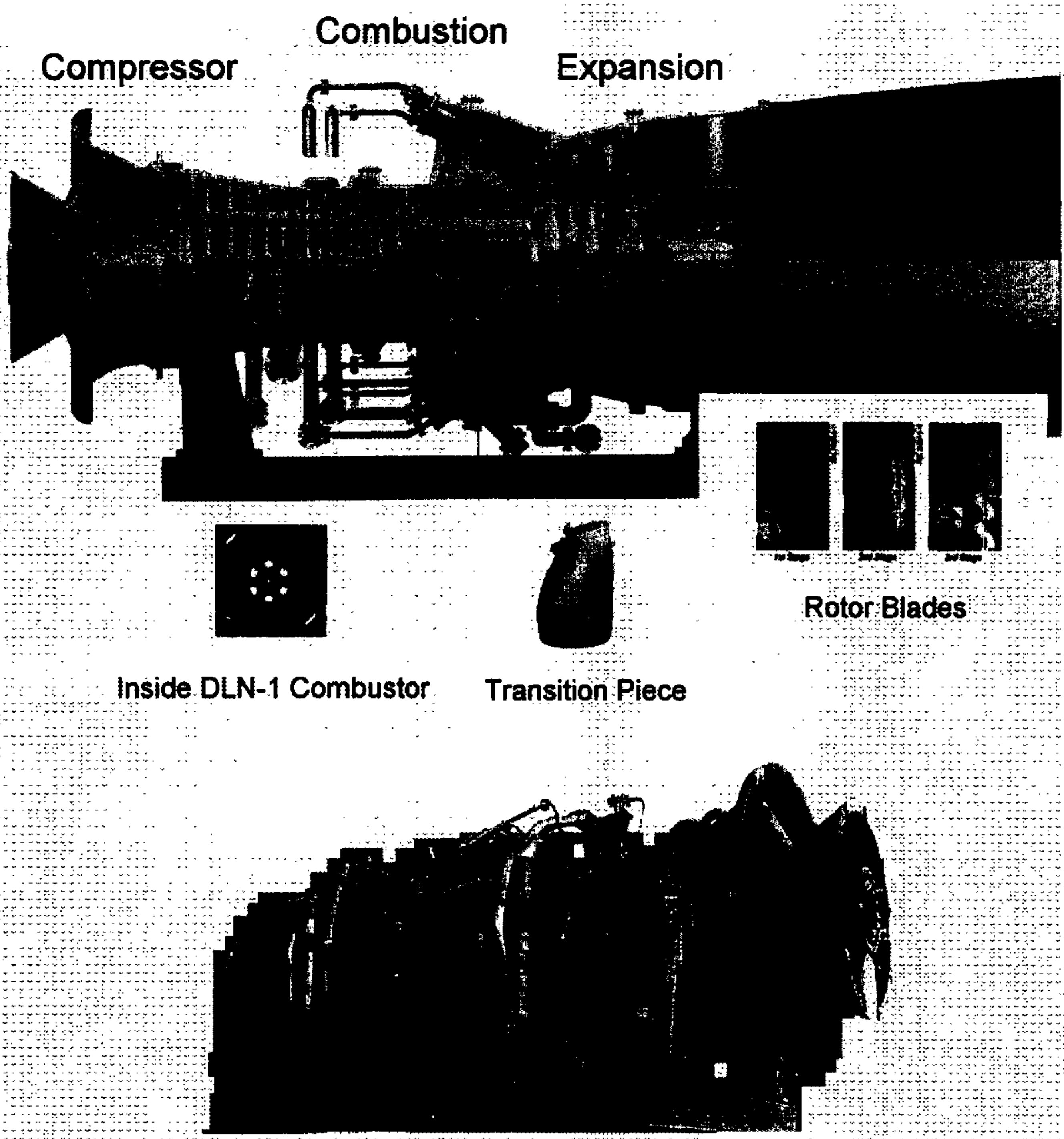


Figure 5 - Internal and External Views of GE MS7001FA

COMBINED CYCLE

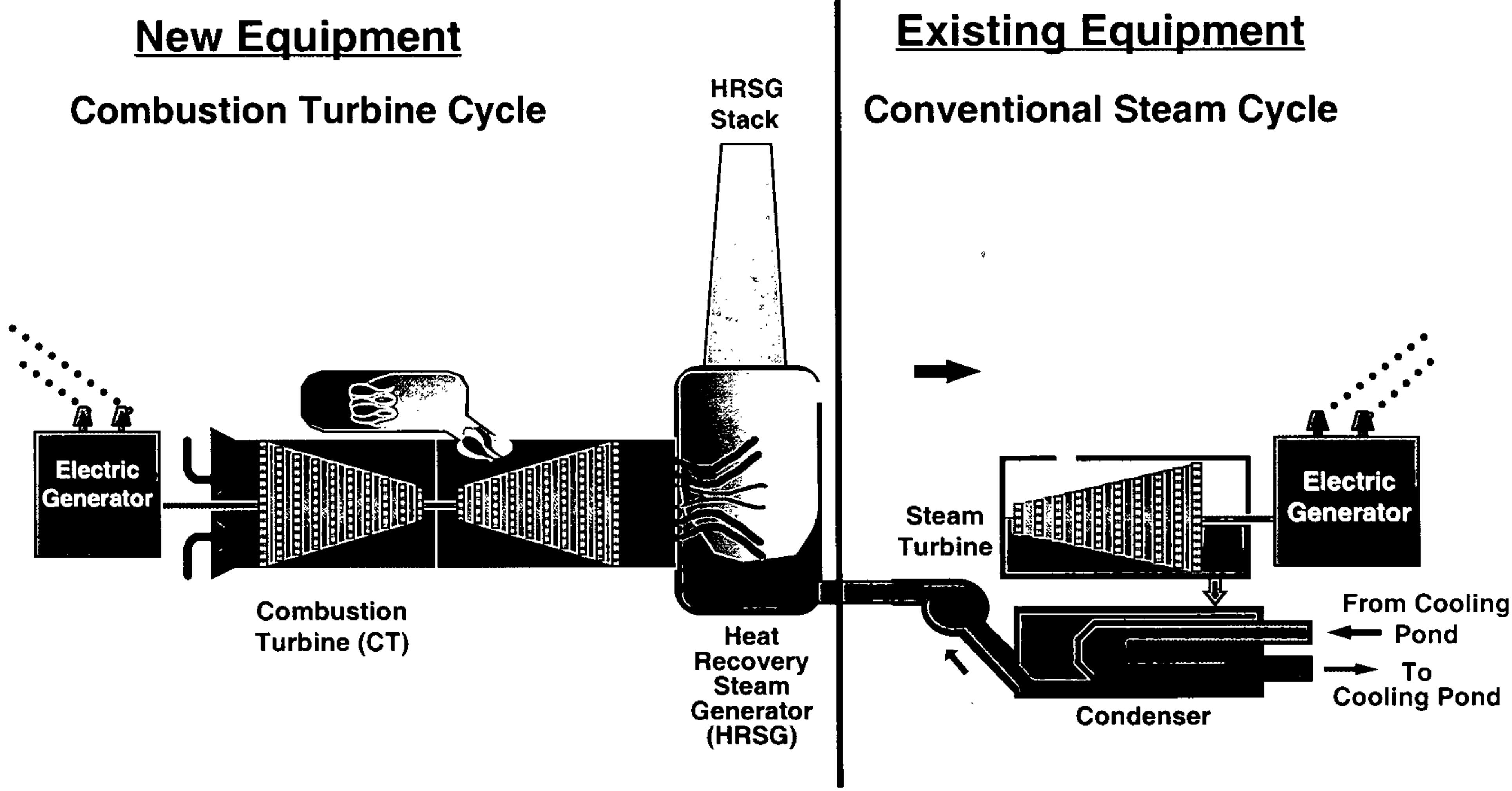


Figure 6. Schematic of FPL Sanford Repowering Project

9837571Y/F1/WP/FIG6 (6/1/99)

Figure 7 – View of Repowered FPL Lauderdale Plant

Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the control technology section below.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 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 Volusia 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) for VOCs. Because the potential emissions for PM/PM_{10}, CO, SO_2 and NO_X decrease with removal of the existing boilers for Units 4 and 5 and do not exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C., PSD review for these and other regulated pollutants is not applicable.

This evaluation consists of a review of the control technology for PM/PM_{10}, VOC, CO, SO_2, and NO_X to insure that it is sufficient to restrict future emissions to levels lower than past emissions or increases in emissions to levels less than the significant emission rates as described above. An analysis of the air quality impact from proposed project is required to insure that there are no exceedances of the National or State Ambient Air Quality Standards.

The emission units affected by this 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

Chapter 62-4	Permits.
Rule 62-204.220	Ambient Air Quality Protection
Rule 62-204.240	Ambient Air Quality Standards
Rule 62-204.800	Federal Regulations Adopted by Reference
Rule 62-210.300	Permits Required
Rule 62-210.350	Public Notice and Comments
Rule 62-210.370	Reports
Rule 62-210.550	Stack Height Policy
Rule 62-210.650	Circumvention
Rule 62-210.700	Excess Emissions
Rule 62-210.900	Forms and Instructions
Rule 62-212.300	General Preconstruction Review Requirements
Rule 62-213	Operation Permits for Major Sources of Air Pollution
Rule 62-214	Requirements For Sources Subject To The Federal Acid Rain Program
Rule 62-296.320	General Pollutant Emission Limiting Standards
Rule 62-297.310	General Test Requirements
Rule 62-297.401	Compliance Test Methods
Rule 62-297.520	EPA Continuous Monitor Performance Specifications

5.2 Federal Rules

40 CFR 60	NSPS Subparts 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. AIR POLLUTION CONTROL TECHNOLOGY

6.1 Applicant Control Technology Proposal

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
Particulate Matter	Pipeline Natural Gas Combustion Controls	
Volatile Organic Compounds	As Above	1.4 ppmvd - gas 7 ppmvw - oil
Carbon Monoxide	As Above	12 ppmvd (CTs) - gas 20 ppmvd - oil 0.15 lb/mmBtu (heater)
Sulfur Dioxide	As Above	1 gr/100 scf (CTs) - gas 0.05% S - oil
Nitrogen Oxides	Dry Low NO_x Combustors (CTs) Water Injection (CTs) Dry Low NO_x Burners (Boiler)	9 ppmvd @ 15% O_2 gas 42 ppmvd @ 15% O_2 0.10 lb/mmBtu (heater)

According to the application, the new CT units will emit approximately 2,680 tons per year (TPY) of NO_X, 1,603 TPY of CO, 119 TPY of VOC, 277 TPY of SO_2, 42 TPY of sulfuric acid mist, and 357 TPY of PM/PM_{10}. The direct fired heaters will emit about 77.1 TPY of NO_X, 116 TPY of CO, 5 TPY of VOC, 2 TPY of SO_2 and 5 TPY of PM/PM_{10}. The cooling tower will emit about 25 TPY of PM and 12.5 TPY of PM_{10}. When the existing units are taken out of service there will be a net reduction of about 28,450 TPY of SO_2, 1,234 TPY of sulfuric acid mist, 7,227 TPY of NO_X, 1,188 TPY of CO, and 151/164 TPY of PM/PM_{10}. An increase of 57 TPY of VOC is expected.

6.2 Standards of Performance for New Stationary Sources

The minimum project control technology basis is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). The Department adopted Subpart GG by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The proposal is consistent with the NSPS, which allows NO_X emissions over 100 ppm for the high efficiency unit to be purchased by FPL. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines.

6.3 Determinations by EPA and States

The following table is a sample of information on recent control technology determinations by EPA and the States for combined cycle projects.

Project Location	Power Output and Duty	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Lakeland, FL	350 MW CC CON	9/9/7.5 - NG 42/15/15 - No. 2 FO	DLN/HSCR/SCR WI/HSCR/SCR	230 MW WH 501G CT Initially 250 MW simple cycle and 25 ppmvd NO_X limit on gas
Duke NS, FL	500 MW CC CON	9/4.5 – NG	DLN/SCR	2x165 MW GE PG7241FA CTs Draft BACT issued 1/99
FPL Ft Myers, FL	1500 MW CC CON	9 - NG	DLN	6x170 MW GE PG7241FA CTs Non-BACT
Santa Rosa, FL	241 MW CC CON	9 - NG (CT) 9.8/6/6 (CT&DB)	DLN DLN/SCR/SNCR	GE PG7241FA CT. 6 ppmvd by SCR/SNCR if DLN fails
KUA Cane Ill, FL	250 MW CC CON	9/4.5 - NG 42/15 - No. 2 FO	DLN/SCR WI/SCR	167 MW PG GE PG7241FA CT Draft BACT issued 1/99
Tallahassee, FL	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE PG7231FA CT DLN guarantee is 9 ppmvd
Eco-Electrica, PR	461 MW CC CON	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW WH 501F CTs
Sithe/IPP, NY	1012 MW CC CON	4.5 - NG	DLN & SCR	4 x160 MW GE 7FA CTs
Hermiston, OR	474 MW CC CON	4.5 - NG	SCR	2x160 MW GE 7FA CTs
Barry, AL	800 MW CC CON	3.5 - NG (CT&DB)	DLN & SCR	3x170 MW GE PG7241FA CTs

CC = Combined Cycle | CON = Continuous | DLN = Dry Low NO_X Combustion | GE = General Electric
DB = Duct Burner | HSCR = Hot SCR | SCR = Selective Catalytic Reduction | WH = Westinghouse
NG = Natural Gas | FO = Fuel Oil | LPG = Liquefied Propane Gas | ppm = parts per million
CT = Combustion Turbine | WI = Water or Steam Injection | SNCR= Selective Non-catalytic Reduction

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Duke NS, FL	12 - NG @15% O_2	2 – NG	10% Opacity	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Santa Rosa, FL	9 - NG (CT) 24 - NG (CT&DB)	1.4 - NG (CT) 8 - NG (CT&DB)	10% Opacity	Clean Fuels Good Combustion
KUA Cane III, FL	12 - NG 20 - FO	1.4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Clean Fuels Good Combustion

6.4 Review of Combustion Turbine Control Technologies

A complete discussion of control options was not required for a majority of pollutants except VOC, because the project is not subject to a Best Available Control Technology Determination. However the applicant discussed the technology to be employed in order to comply with the New Source Performance Standards and the requested limits. The Department has included other information typically included in a complete BACT determination for comparison purposes.

6.4.1 Nitrogen Oxides Formation

Much of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

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 lean, 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. It is not important for the FPL project because natural gas will be the primary fuel used.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppm @15% O_2). For large modern turbines, the Department estimates uncontrolled emissions at approximately 200 ppm @15% O_2.

6.4.2 NO_x Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces 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 increase emissions of both of these pollutants.

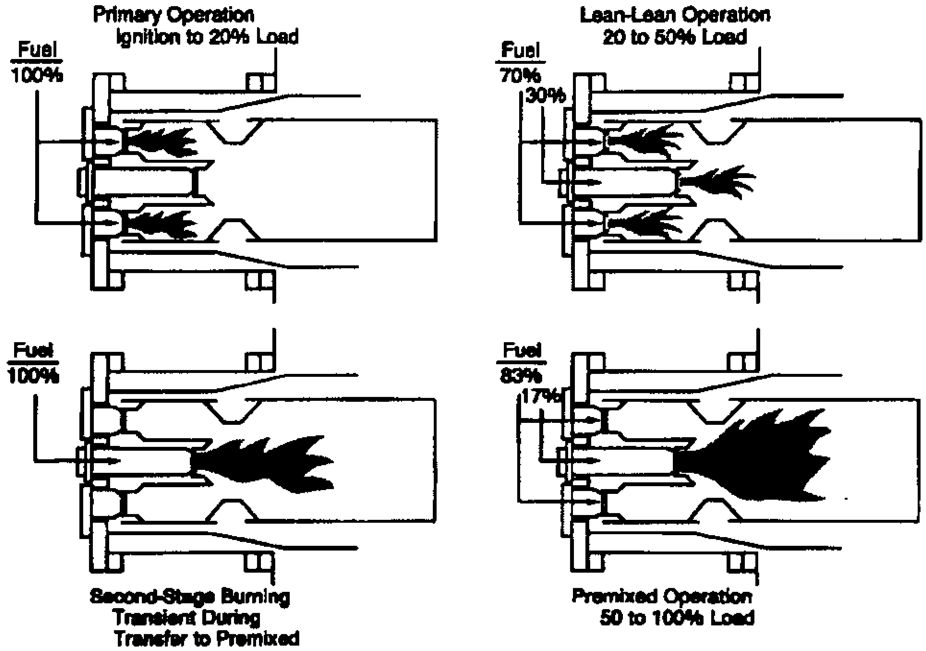
Combustion Controls

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 8 for a General Electric can-annular combustor operating on gas. 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 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.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 8) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the FPL project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 9 for a unit tuned to meet a 15 ppmvd



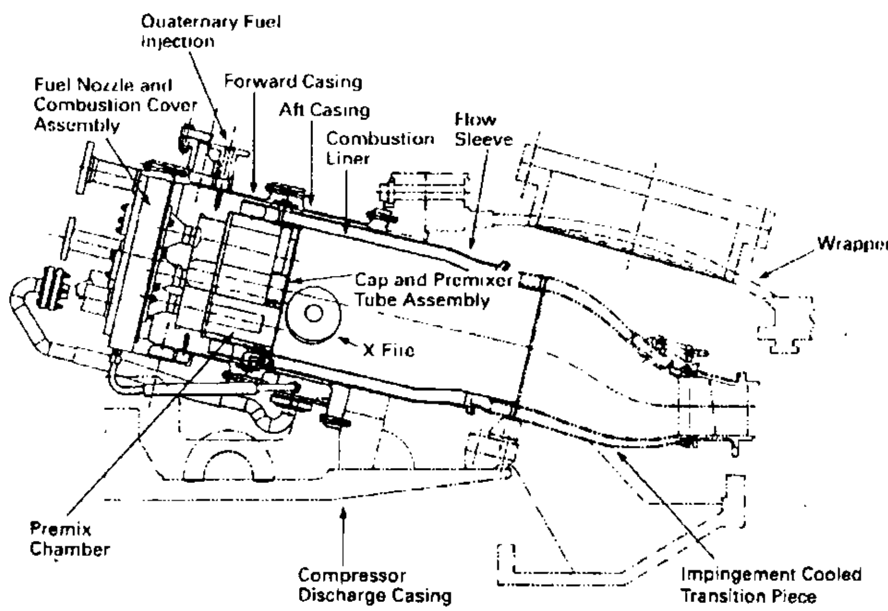


Figure 8 - Dry Low NOx Operating Modes - DLN-1

Cross Section of DLN-2.0

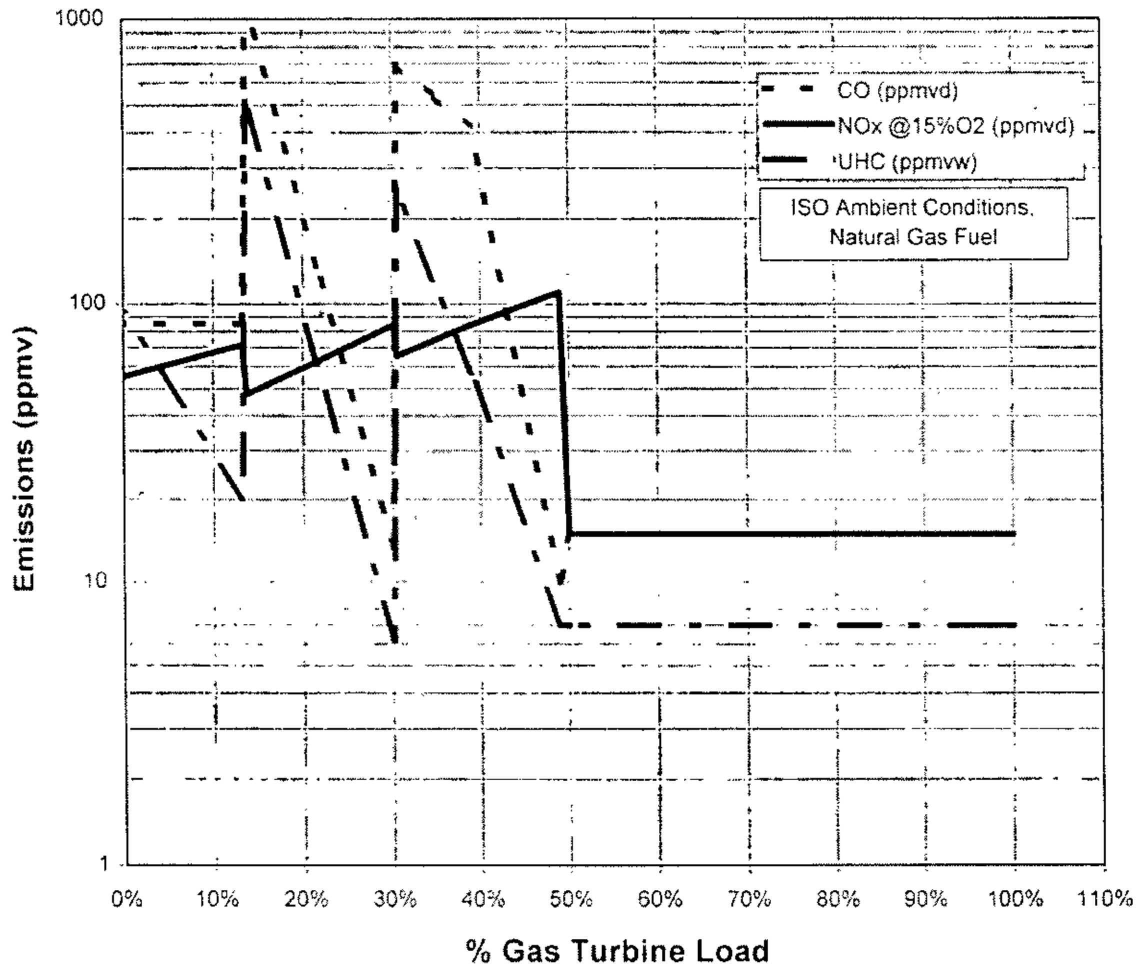


Figure 9 - Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle, Intermittent Duty - If Tuned to 15 ppm NOx)

NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 parts per million by volume, dry, (ppmvd) at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppm of CO. Emissions characteristics while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 10. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the FPL project are shown in Figure 11.

In all but the most recent gas turbine combustor designs, 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, results in a lower achievable thermal efficiency for the unit.

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to the steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 12 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are low as 9 ppmvd from gas turbines smaller than 200 MW (simple cycle), such as GE "F Class" units. Even lower NO_X emissions are achieved from certain units smaller than 100 MW, such as the GE 7EA line.

With the implementation of the Repowering Project, NO_x emissions will decrease by about 7,227 TPY compared to current actual emissions. This decrease includes the repowered units emitting at 2,757 TPY of NO_x.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur bearing fuels are used).

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously-permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Permit limits as low as 2.25 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The Department did, however, specify SNCR as one of the available options for the combined cycle Santa Rosa Energy Center. The project will incorporate a large 600 MMBtu/hr duct burner in the heat recovery steam generator (HRSG) and can provide the acceptable temperatures (between 1400 and 2000 °F) and residence times to support the reactions.

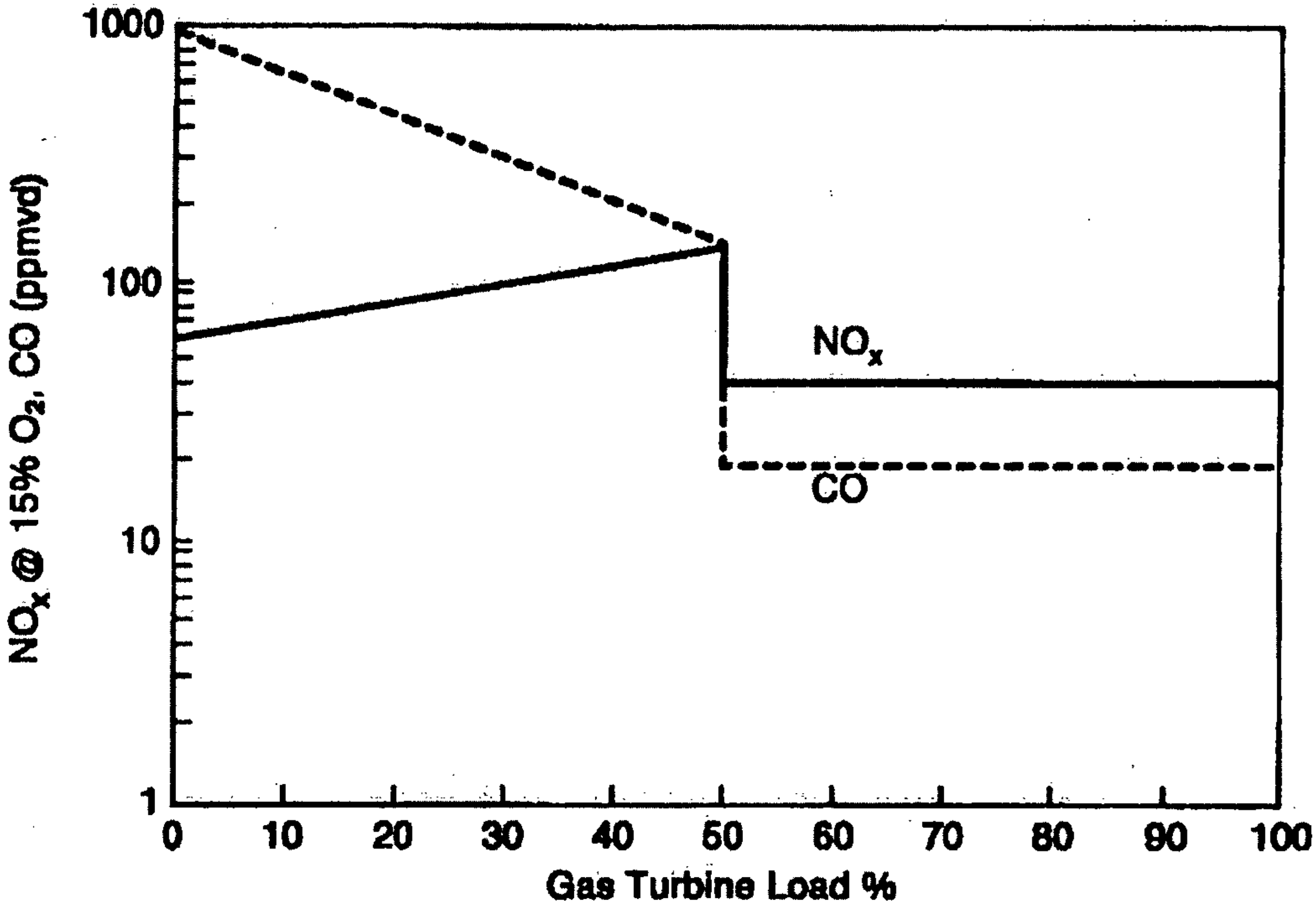


Figure 10 - Emissions Performance Curves for DLN-2 Combustor

Firing Fuel Oil in Dual Fuel GE 7FA Turbine

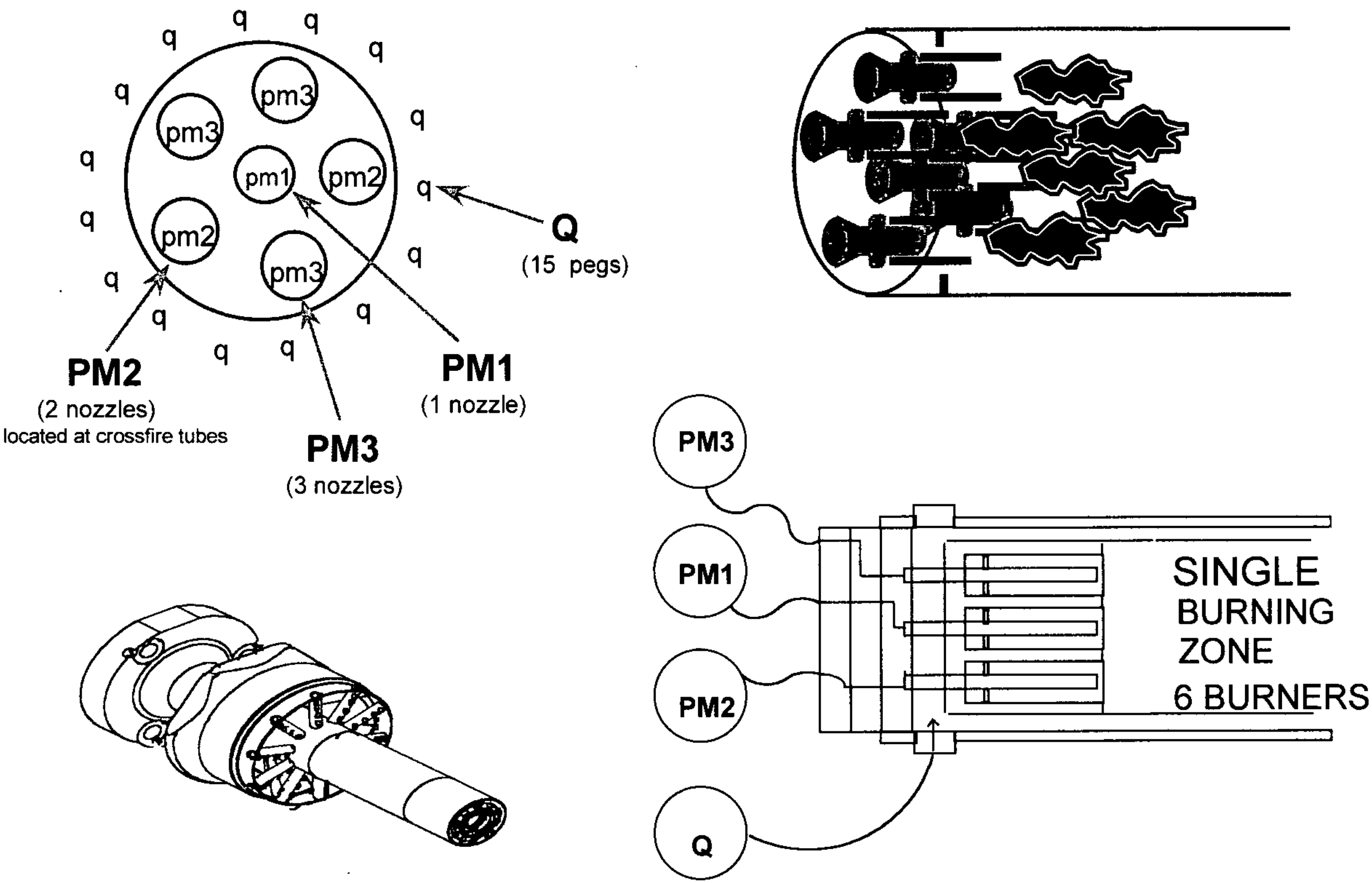


Figure 11 - DLN2.6 Fuel Nozzle Arrangement

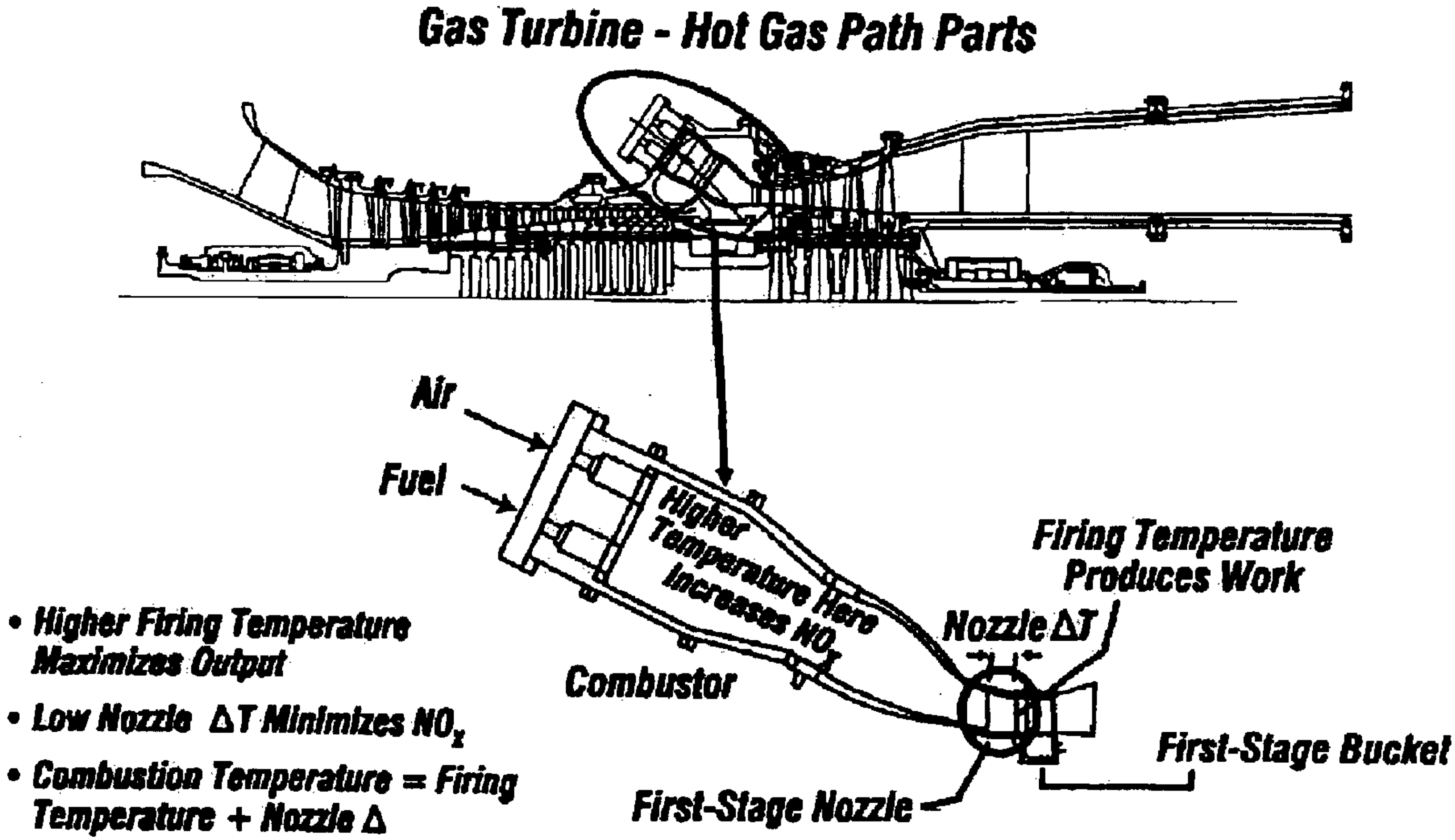


Figure 12 - Relation Between Flame Temperature and Firing Temperature

Emerging Technologies: SCONOX™ and XONON™

There are at last two technologies on the horizon that will influence BACT determinations. These, as usual, are prompted by the needs specific to non-attainment areas such as Southern California.

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[3] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[4] The overall project includes several more 250 MW blocks with SCR for control.[5] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of some CO emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, EPA deemed the SCONOx™ process technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998). SCONOx requires a much lower temperature regime that is not available in simple cycle units and is therefore not feasible for this project. Therefore the SCONOx system cannot be considered as achievable or demonstrated in practice for this application.

The second technology is XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as $SCONO_X$™ has. However GE has teamed with Catalytica to develop a combustor for gas turbines in the 80-90 MW range before continuing with development on a combustor for a larger unit.

XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view if it works.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON^{TM} Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON^{TM} Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON^{TM} Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON^{TM} system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

Catalytica's XONON^{TM} system is represented as a powerful technology that essentially eliminates the formation of nitrogen oxides air emissions in gas turbines without impacting the turbine's operating performance. In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON^{TM} systems for both new and installed GE E-class and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

6.4.3 Particulate Matter (PM/PM_{10}) Control

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 combusted in gas turbines. Clean 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 its use is proposed only at the four turbines replacing Unit 5 and limited to an aggregate of 500 hrs/yr per turbine.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. The applicant has chosen this approach and the Department concurs. Annual emissions of PM/PM_{10} are expected not to exceed 387 tons per year (eight combustion turbine, cooling tower and small heater). This represents a decrease of about 151 TPY.

Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.001 percent of the circulating water flow rate. No PM testing is required.

6.4.4 Carbon Monoxide (CO) Control

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.

All combustion turbines using catalytic oxidation appear to be combined cycle units. Among the most recently permitted ones are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium 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 recently proposed catalytic oxidation in order to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.6

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically have CO limits between 10 and 25 ppm at full load while firing gas. The values of 12 and 20 ppm for gas and oil respectively at baseload proposed in the FPL's application are within the range of recent determinations for CO BACT determinations. Values given in GE-based "F technology" applications are applicable to fully pre-mixed operations between 50 and 100 percent of full load. For reference the Department has found that actual emissions at full load for modern F-Class turbines on gas or oil are much less than 10 ppm based tests based on compliance tests.[7, 8]

By comparison, the value of 12 ppm proposed FPL's application appears relatively low, but consistent with the capabilities of the DLN-2.6 technology as discussed above. The net emissions from implementing the repowering project will decrease by CO emissions of about 1,188 TPY.

6.4.5 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist SAM Control

SO_2 control processes can be classified into five categories: fuel/material sulfur content limitation, absorption by a solution, adsorption on a solid bed, direct conversion to sulfur, or direct conversion to sulfuric acid. A review of the BACT determinations for combustion turbines contained in the BACT Clearinghouse shows that the exclusive use of low sulfur fuels constitutes the top control option for SO_2.

For this project, the applicant has proposed the use of 0.05% sulfur oil and natural gas containing no more than 2 grains of sulfur per 100 standard cubic foot (gr S/100 ft^3). This value is well below the "default" maximum value of 20 gr. S/100 ft^3. The applicant estimated total emissions for the project at 279 TPY of SO_2 and 42.3 TPY of SAM. However the Department expects the emissions to be lower because typical the natural gas in Florida contains less than 1 gr S/100ft^3.and the typical distillate fuel oil is usually less than 0.02% sulfur. With the implementation of the Repowering Project, SO_2 and SAM emissions will decrease by at least 28,450 TPY and 1,234 TPY, respectively, compared to recent actual emissions.

6.4.6 Volatile Organic Compound (VOC) Control

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC to 1.4 ppm while firing natural gas and 7 ppmvw when firing distillate oil. The limit for gas firing is equal to the lowest BACT-based VOC limit listed above. The limit for oil in consistent with levels established as BACT. According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[9]

Annual emissions of VOC are expected to be approximately 119 TPY from the repowered units and 4.6 TPY for the direct fired heaters. The difference between future emissions and past actual emissions is greater than the 40 TPY significant emission rate increase. Therefore both PSD and BACT are applicable for VOC emissions.

6.5 Background on Selected Gas Turbine

FPL has purchased eight (8) 170 MW General Electric MS7241FA combined cycle gas turbines with un-fired HRSGs. By using two existing steam turbine-electrical generators, each combustion turbine will produce approximately another 80 MW of electrical power.

The first commercial GE 7F Class unit was a installed at the Virginia Power Chesterfield Station in 1990.[10] The initial units had a firing temperature of 2300°F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400°F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[11] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[12] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[13] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[14] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[15] The Santa Rosa Energy Center in Pace, Florida also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[16]

Most recently, the Department issued draft BACT determinations for the simple cycle Oleander project in Brevard County and the TEC project in Polk County. The Department also issued draft permits for combined cycle projects in Volusia (Duke Energy), and Osceola (Kissimmee Utilities), and Palm Beach (Lake Worth). Four of these draft permits also include NO_X limits of 9 ppmvd based on the DLN-2.6 technology installed on F Class units. The TEC simple cycle project has a requirement to meet the "new and clean" guarantee emission limit of 9 ppmvd, but is only required to comply with a limit of 10.5 ppmvd based on CEMS thereafter.

GE's approach of progressively refining such technology is a proven one for the large frame units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[17] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[18] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the ones that will be installed for the FPL Sanford Project. Performance guarantees less than 9 ppmvd can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[19]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Caution is still advised, however, based on some unexpected setbacks in GE's line of smaller aero-derivative units. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[20]

The 9 ppm NO_X limit on natural gas requested by FPL is comparable with recent BACT determinations for F Class combined cycle units, such as those previously listed. This is also the same limit for the Fort Myers Repowering Project that involves six (6) GE Frame 7FA turbines.

6.6 Control Technology Determination

Following are the emission limits determined for the FPL project assuming full load. Values for NO_X are corrected to 15% O_2. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times, are given in the permit Specific Conditions.

Emission Unit	NO_X	CO	VOC BACT	PM/Visibility (% Opacity)	Technology and Comments
Combustion Turbines	9 ppm - gas 42 ppm - oil 75/110 ppm (NSPS)	12 ppm - gas 22 ppm - oil	1.4 ppm - gas 7 ppm - oil	10 - gas 20 - oil	Dry Low NO_X Combustors Natural Gas, Good Combustion, Water Injection (oil), Low sulfur distillate oil
Heater	0.10 lb/mmBtu	0.15 lb/mmBtu	-	-	Dry Low NO_X Burners
Cooling Tower					Unregulated Unit

6.7 Rationale for Control Technology Determination

- FPL obtained a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on "7FA" Class gas turbines.
- FPL specifically requested that these limits be incorporated into the permit although the project could "net out" of PSD review and BACT with higher limits (except for VOC).
- All of the combustion turbine emission limits comply with the NSPS and are less than or equal to recent Department BACT determinations applicable to new units at start-up.
- PM_{10} emissions will be very low and difficult to measure. The Department, with FPL's concurrence, will set a visible emission standard of 10 percent opacity (20% on fuel oil).

- CO emissions from FPL's project are low (approximately 9 ppm). With FPL's concurrence, the Department will set CO limits achievable by good combustion equal to 12 and 20 ppm for gas and oil respectively.
- **VOC** emissions of **1.4 ppm** proposed by FPL are at the lower end of values determined as BACT. This limit **constitutes a draft BACT determination for this project while firing gas**. Good Combustion is sufficient to achieve these low levels with the DLN-2.6 combustors while firing natural gas. A **VOC** emission limit of **7 ppm** for oil is toward the low end of values determined as BACT and **also constitutes a draft BACT determination for this project while firing oil.**

6.8 Compliance Procedures

Pollutant	Compliance Procedure
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (30-day average for gas and 24-hour block average for oil)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (NSPS initial performance)	Method 20 (can use RATA if at capacity)

6.9 Excess Emissions

Allowable Excess Emissions: Pursuant to Rule 62-210.200 F.A.C., excess emissions are allowable under the following scenarios: Valid hourly emission rates shall not included periods of startup (~240 minutes), shutdown (~180 minutes), or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in permit Specific Condition 27. 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. [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request]

7. SOURCE IMPACT ANALYSIS

7.1 Emission Limitations

The proposed eight combustion turbines, cooling tower and heaters 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, fluorides, beryllium, mercury and lead. The applicant's proposed annual emissions are summarized in the Table below and form the basis of the source impact review.

The existing 156 MW residual oil and gas-fired Unit 3 will be retained. However its future operation will be limited as a result of plant-wide emissions caps requested by FPL. These proposed caps include the emissions in the Table below and are equal to 500 TPY of

PM/PM10, 4,500 TPY of NOX, and 4000 TPY of SO2. According to EPA's acid rain data, the entire plant emitted 38,660 TPY of SO2 and 16,878 TPY of NOX in 1998. Absent this repowering project and the proposed plant-wide emissions cap, the permitted emissions from the plant are over 100,000 TPY of SO2 alone and there is no NOX limit.

7.2 Emission Summary

The net emissions increase/decrease for all PSD pollutants as a result of this modification are calculated below:

CONTEMPORANEOUS CREDITABLE CHANGES (TPY)

Pollutants	Past Actual Emissions (Units 4 and 5)	Future Emissions (Repowered)	Increase (decrease)	PSD Significance	PSD Review?
PM/PM_{10}	538	387/374	(151/164)	25/15	No
SAM	1,276	42.3	(1,234)	7	No
SO_2	28,729	279	(28,450)	40	No
NO_X	9,984	2,757	(7,227)	40	No
VOC	67	124	57	40	Yes
CO	2,906	1,719	(1,188)	100	No

7.3 Air Quality Analysis

7.3.1 Introduction

The proposed project will not result in the increase of emissions of any PSD pollutants at levels in excess of PSD significant amounts, with the exception of VOC emissions. Emissions of all other PSD pollutants will actually decrease due to the project. However, as a supplement to the air permit application, FPL estimated air quality impacts for the existing plant and the repowered plant including impacts related to construction activities and future operations. This supplemental air quality analysis was done for PM_{10}, CO, SO_2 and NO_x emissions. Emission of VOCs are related to the formation of ozone and are not modeled for individual sources. The VOC emissions increase is, however, less than the major source threshold (100 TPY) and the *de minimis* monitoring level (also 100 TPY).

Based on these 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. A discussion of these analyses follows.

7.3.2 Models and Meteorological Data Used in the Air Quality Impact Analysis

The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. The model 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 Orlando International Airport, Florida (surface data) and Ruskin, Florida (upper air data). The 5-year period of meteorological data was from 1987 through 1991. 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.

7.3.3 AAQS Analysis

An AAQS analysis was done for PM_{10}, SO_2 and NO_2 due to the project. Predicted CO impacts from the project were less than the applicable significant impact levels; therefore, no further CO modeling for comparison with the AAQS was required. Total air quality impacts for comparison with the PM_{10}, SO_2 and NO_2 AAQS were estimated by adding the maximum predicted concentrations due to project-related sources to background concentrations. Background concentrations are concentrations due to sources not associated with the Sanford plant. These concentrations consist of two components: impacts due to other modeled emission sources in the area, and impacts due to sources not explicitly modeled. The non-modeled background concentrations were obtained from air quality monitoring data. The AAQS analysis submitted with this proposed project, and summarized in the two tables below shows that maximum predicted total impacts from PM_{10}, SO_2 and NO_2 emissions do not exceed the AAQS.

Ambient Air Quality Impacts During Construction

Pollutant	Averaging Time	Modeled Sources Impact (ug/m^3)	Background Monitor Concentration (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
SO_2	Annual	15	5	20	NO	60
	24-hour	168	18	186	NO	260
	3-hour	453	71	524	NO	1300
PM_{10}	Annual	4.8	23	28	NO	50
	24-hour	37	49	86	NO	150
NO_2	Annual	43	29	72	NO	100

Ambient Air Quality Impacts for Future Operations After Project Completion

Pollutant	Averaging Time	Modeled Sources Impact (ug/m^3)	Background Concentration (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
SO_2	Annual	3	5	8	NO	60
	24-hour	37	18	55	NO	260
	3-hour	198	71	269	NO	1300
PM_{10}	Annual	0.3	23	23	NO	50
	24-hour	4.7	49	54	NO	150
NO_2	Annual	2.2	29	31	NO	100

7.3.4 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 (the baseline year was 1975 for existing major sources of SO_2) for SO_2 and 1988 for NO_2. This project will expand increment since the proposed emissions after the project is completed will be less than the emissions of these pollutants during the baseline years.

7.3.5 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

The maximum ground-level concentrations predicted to occur for PM_{10}, CO, and NO_X as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils and vegetation in the vicinity of the plant or the PSD Class I area in the Chassahowitzka National Wilderness Area. In addition, there should be an amelioration of any impacts from the existing plant due to the reduction in acid particulate deposition.

7.3.6 Impact On Visibility

Visibility should improve in the immediate area based on lower emissions of particulate and particulate pre-cursors. The stack visible emissions limits of 10/20 percent opacity (gas/oil) compared with present limits as high as 40 percent will further insure an improvement.

7.3.7 Growth-Related Air Quality Impacts

The proposed project is being constructed to meet current and future state-wide electric demands. Additional growth in the immediate area as a direct result of the additional electric power provided by the project is not expected. The project will be constructed and operated with minimum labor and associated facilities and is not expected to significantly affect growth in the local area. Obviously any increase in highly efficient electric power capacity promotes or accommodates further state-wide growth.

8. CONCLUSION

Based on the foregoing technical evaluation of the application and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations. Furthermore the project will improve ambient air quality in the area and reduce acidic particulate deposition.

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

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PERMITTEE:

Florida Power & Light Company
Sanford Power Plant
950 South Highway 17-92
DeBary, Florida 32713

Permit No.	1270009-004-AC (PSD-FL-270)
Project:	2200 MW Repowering Project
SIC No.	4911
Expires:	December 31, 2003

Authorized Representative:

Roxane Kennedy
Plant General Manager

PROJECT AND LOCATION:

Permit to install eight (8) combined cycle units to replace two (2) residual oil-fired and gas-fired steam generating units. Each unit is a 170 megawatt General Electric MS7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with two existing residual oil-fired and gas-fired units (872 MW total capacity for Units 4 and 5) will be dismantled and replaced by relatively short stacks per unit for simple cycle (Repowered Unit 4 only) and combined cycle operation. The project also includes a cooling tower for once-through cooling pond water and small heaters with a 10-foot stack to heat the natural gas prior to use during simple cycle operation and cold start-ups.

This facility is located at 950 South Highway 17-92, DeBary, Volusia County. UTM coordinates are: Zone 17; 468.3 km E and 3,190.3 km N.

STATEMENT OF BASIS:

This 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 MADE A PART OF THIS PERMIT:

Appendix GC Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

Currently, this facility generates electric power from three residual fuel oil-fired and gas-fired steam units with a combined generating capacity of 1,028 megawatts (MW).

This permitting action (2,200 MW Repowering Project) is to install eight (8) combined cycle units to replace two (2) residual oil-fired and gas-fired steam generating units. Each unit is a 170 megawatt General Electric MS7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with two existing residual oil-fired and gas-fired units (872 MW total capacity) will be dismantled and replaced by relatively short stacks per unit for simple cycle and combined cycle operation. The project also includes a cooling tower for once-through cooling pond water and small heaters with 10-foot stacks to heat the natural gas prior to use during simple cycle operation and cold start-ups.

This Project is exempt from the requirements of Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) as discussed stated in the Technical Evaluation and Preliminary Determination dated July 30, 1999, for all pollutants except Volatile Organic Compounds (VOCs).

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
004-011	Power Generation	Eight (8) Combined Cycle Combustion Turbine-Generators with Unfired Heat Recovery Steam Generators
012-019	Fuel Heating	Natural Gas Heater(s)
020	Water Cooling	Mechanical Draft Cooling Tower

REGULATORY CLASSIFICATION

This facility, FPL Sanford Power Plant, 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 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- _______ Notice of Intent published in the _________
- 7/30/99 Distributed Intent to Issue Permit
- 6/15/99 Received Application

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 on June 15, 1999
- U.S. Fish and Wildlife Service comments dated June 22, 1999
- Department's Intent to Issue and Public Notice Package dated July 30, 1999
- EPA comments dated ______.
- FPL's comments dated ______.
- FPL's submittal of revised Phase II Acid Rain application dated ______

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND 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 (DEP), at 2600 Blairstone 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 Central District office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number (407) 894-7555.

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. 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]

6. Permit Extension: *This permit expires on December 31, 2003.* The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. [Rule 62-4.080, F.A.C.].

7. 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 sent to the Department's Central District office. [Chapter 62-213, F.A.C.] The application shall reflect the plant-wide emission caps requested in this proposed repowering project. [Applicant's Request]

8. 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.]

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

9. 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 Central District office by March 1st of each year.
10. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.
11. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District office.

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

APPLICABLE STANDARDS AND REGULATIONS:

1. 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, 62-103, 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 Section 40, Parts 60, 72, 73, and 75.

2. 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.]

3. These emission units shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions including:
   - 40 CFR 60.7, Notification and Recordkeeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting requirements

4. ARMS Emission Units 004 through 011, Power Generation, consisting of eight (nominal) 170 MW combustion turbines (250 MW in combined cycle operation), 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. However, such correction is not required to demonstrate compliance with non-NSPS permit standard(s).

5. ARMS Emission Unit 012-019, Fuel Heating, shall comply with all applicable provisions in this permit.

6. ARMS Emission Unit 020, Cooling Tower, is an unregulated emission unit.

7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District office.

GENERAL OPERATION REQUIREMENTS

8. Fuels: Pipeline natural gas shall be the primary fuel fired in these units. When gas is not available, up to 28,600,000 gallons per year of distillate oil (0.05% sulfur) is authorized for repowered Unit 5; (ARMS emission units 008-011). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Turbine Capacity: The maximum heat input rates for natural gas firing, based on the lower heating value (LHV) of the fuel to *each* combustion turbine at compressor inlet conditions of 59°F, 60% relative humidity, 100% load, and 14.7 psia shall not exceed 1,600 million Btu per hour (MMBtu/hr). The maximum heat input for oil firing is 1,820 MMBtu/hr (LHV, 60% relative humidity, 100% load, 59°F compressor inlet and 14.7 psia). This maximum heat input rate will vary depending upon turbine inlet conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other compressor inlet 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)]

10. Direct Fired Heaters (DFHs). The maximum heat input rate, based on the lower heating value (LHV) of the fuel to the DFHs at ambient conditions of 59°F, 60% relative humidity, 100% load, and 14.7 psia shall not exceed 176 MMBtu per hour.

11. 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.

12. 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 Central District 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.]

13. Operating Procedures: Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment. [Rule 62-4.070(3), F.A.C.]

14. Circumvention: The owner or operator 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.]

15. Maximum Annual Allowable Hours of operation for each of the eight combustion turbines, the cooling tower, and the gas heaters (ARMS Emission Units 004-020) are 8,760. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

16. Dry Low NO_X (DLN) combustor shall be installed on each stationary combustion turbine to control nitrogen oxides (NO_X) emissions. Water injection shall be installed in the turbine for Repowered Unit 5 to control NO_x when firing distillate oil. [Design, Rule 62-4.070, F.A.C.]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following are the emission limits determined for this project assuming full load. Values for NO_X are corrected to 15% O_2 on a dry basis. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times, are followed by the applicable specific conditions. [Applicant Requests, Rules 62-204.800(7)(b) (Subparts GG), 62-210.200 (Definitions-Potential Emissions), F.A.C.].

Emission Unit	NO_X	CO	VOC	PM/Visibility (% Opacity)	Technology and Comments
Combustion Turbines (each)	9 ppm (30 day) - gas 42 ppm - oil 75/110 ppm (NSPS)	12 ppmvd - gas 20 ppmvd - oil	1.4 ppmvd 7 ppmvw	10 - gas 20 - oil	Dry Low NO_X Combustors Natural Gas or 0.05% S Fuel Oil Good Combustion Water Injection on Fuel Oil
Gas Heaters	0.10 lb/mmBtu	0.15 lb/mmBtu		10	Low NO_X Burners

19. <u>Nitrogen Oxides (NO_X) Emissions:</u>

- The concentration of NO_x concentrations in the exhaust gas of each CT shall not exceed 9 ppmvd at 15% O_2 on a 30-day rolling average basis when firing natural gas as measured by the CEMS (maintained in accordance with 40 CFR 75). Based on CEMS data at the end of each operating day, a new 30-day average rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. In addition, NO_x emissions calculated as NO_2 (at ISO conditions) shall exceed neither 9 ppm at 15% O_2 nor 65 lb/hr to be demonstrated by initial performance test.
- The concentration of NO_X concentrations in the exhaust gas of each CT shall not exceed 42 ppmvd at 15% O_2 on a 24-hour block average basis when firing distillate oil as measured by the CEMS (maintained in accordance with 40 CFR 75). Based on CEMS data at the end of each operating day, a new 24-hour average rate is calculated from the arithmetic average of all valid hourly emission rates during the previous day. In addition,

NO_x emissions calculated as NO_2 (at ISO conditions) shall exceed neither 42 ppm at 15% O_2 nor 355 lb/hr to be demonstrated by initial performance test.

- When NO_x monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30 day rolling average or 24-hour block average emission rates.
- NO_x emission limit from the gas heaters shall not exceed 0.10 lb/mmBtu (at ISO conditions) to be demonstrated by representative stack test on one unit. The permittee may construct one heater within the heat input limit specified in Specific Condition 10. If the unit is classified as a "steam generating unit" in 40 CFR 60.41b, than the requirements of 40 CFR Subpart Db apply.

20. Visible Emissions (VE): VE emissions from the combustion turbines shall not exceed 10 percent opacity during gas firing and 20 percent opacity during oil firing. Visible emissions from the gas heaters shall not exceed 10 percent opacity.
21. Carbon Monoxide (CO) emissions: The concentration of CO (@15% O_2 in the exhaust gas shall not exceed 12 ppmvd when firing natural gas and 20 ppmvd when firing distillate oil as measured by EPA Method 10 at full-load conditions. CO emissions (at ISO conditions) shall not exceed 43 lb/hr (per CT) when firing natural gas and 71.6 lb/hr (per CT) when firing distillate oil to be demonstrated by stack test.
22. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas shall not exceed 1.4 ppmvd when firing natural gas and 7 ppmvw when firing distillate oil as determined by EPA Methods 18 or 25 A. VOC emissions (at ISO conditions) shall not exceed 2.9 lb/hr per CT when firing natural gas and 16.1 lb/hr when firing distillate oil to be demonstrated by initial stack test.
23. Sulfur Dioxide (SO_2) emissions: As per Condition 8.

EXCESS EMISSIONS

24. Excess Emissions Requirements:
    - Excess emissions resulting from startup, shutdown, or malfunction of the *combustion turbines and heat recovery steam generators* 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 during both "cold start-up" to or shutdowns from combined cycle operation. During cold start-up to combined cycle 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. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.

- Excess emissions from the combustion turbines resulting from startup of the *steam turbines system* 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 12 hours per cold startup of the steam turbine system.

  [Applicant Request (FPL estimates that, on average, there will be approximately 12 startups to combined-cycle operation per year), G.E. Combined Cycle Startup Curves Data and Rules 62-210.700, 62-4.130 F.A.C.].

25. Excess emissions 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.

26. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office 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, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

27. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which each unit will be operated, but not later than 180 days following initial operation of the unit, 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.

28. Initial (I) performance tests shall be performed pursuant to 40 CFR Subpart GG. 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 each CT 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).
    - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, 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.
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Reference Method 19. "Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates". Method 19 shall be used only for the calculation of lb/mmBtu and 40 CFR 75 shall be used to calculate mmBtu/hr and lb/hr emissions rates from stack tests. Initial test only.

29. <u>Continuous compliance with the NO_X emission limits</u>:

- Continuous compliance with the NO_X emission limits when firing natural gas shall be demonstrated with the CEM system based on a 30-day rolling average. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction. [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 24-hour block average. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and is calculated from the arithmetic average of all valid hourly emission rates during the previous day. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction. 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. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

30. <u>Compliance with the SO_2 and PM/PM_{10} emission limits</u>: Notwithstanding 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}. The use of very low sulfur (0.05% or less) is the method of compliance for SO_2 and PM_{10}.

    For the purposes of demonstrating compliance with the 40 CFR 60.333, when firing natural gas, data from the pipeline natural gas supplier may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. Gas analysis, if conducted, 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). However, the applicant is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used for determination of fuel sulfur content if gas analysis is done.

    Compliance when firing distillate oil, shall follow the requirements of 40 CFR 60.33.4(a)(1) using methods specified in ASTM 2880-96 (or latest version).

31. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test while operating at permitted capacity. These initial NO_X and CO test results shall be the average of three runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual NOx RATA testing which is performed pursuant to 40 CFR 75.

32. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as a surrogate and no annual testing is required.

33. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet 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. compressor inlet temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for compressor inlet temperature) and 105 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. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204 and 62-297 F.A.C.

34. Test Notification: The DEP's Central District office 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).

35. 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.

36. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

37. Records: All measurements, records, and other data required to be maintained by the permittee 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.

38. Emission Compliance Stack Test Reports: A test report indicating the results of the required compliance tests shall be filed with the DEP Central District Office as soon as practical, but no later than 45 days after the last sampling run is completed. [Rule 62-297.310(8), F.A.C.]. 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.

MONITORING REQUIREMENTS

39. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each CT. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the standards, listed in Specific Condition No 18 and 19, shall be provided to the DEP Bureau of Air Monitoring and Mobile Sources pursuant to 40 CFR 75 and a copy to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile within one working day). [Rule 62-210.700 F.A.C., Rule 62-4.130, F.A.C., and 40 CFR 75].

40. CEMS for reporting excess emissions:, The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (1998 version). Frequency data reports shall be as specified in 40 CFR 60.7(c). Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rule 62-204.800 F.A.C., and 40 CFR 60.7]

41. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NOx CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c) (2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NOx CEMS. Upon request from DEP, the CEMS emission rates for NOx on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

42. Continuous Monitoring System Reports: 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 40 CFR 75. 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 .

43. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

- 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 (DR), that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions 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 pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the Sanford Station, 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).

45. Determination of Process Variables:
    - 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, weigh hoppers, flow meters, and tank scales, 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]

46. Facility-wide Emission Caps. The entire facility including repowered Units 4 and 5 and existing Unit 3, shall be limited to emission caps of 500 TPY of PM/PM_{10}, 4,500 TPY of NO_X, and 4,000 of SO_2. [Applicant Request]

APPENDIX GC

GENERAL PERMIT CONDITIONS [F.A.C. 62-4.160]

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 VOC (X)
b) Determination of Prevention of Significant Deterioration for VOC (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.

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:

DEP File No. 1270009-004-AC

Florida Power & Light Company
FPL Sanford Plant
Volusia County

Project type:

Project to install eight (8) 250 megawatt (MW) combined cycle units to replace two (2) gas and residual oil-fired steam generators at the Sanford Plant, located in DeBary, Volusia County. Each unit is a 170 megawatt General Electric PG7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. Four of the units will be capable of firing back-up No. 2 (0.05% sulfur) distillate fuel. The boilers and the tall stacks associated with existing gas and residual oil-fired units (872 MW total capacity) will be dismantled. The project also includes: a cooling tower for once-through brackish water; a small boiler or heaters to heat the natural gas prior to use; and twelve relatively short stacks for simple and combined (with HRSG) operation.

Nitrogen Oxides emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of carbon monoxide will be controlled to 12 ppm, while emissions of volatile organic compounds will be less than 1.4 ppm. Emissions of sulfur dioxide, sulfuric acid mist, and particulate matter will be very low because of the switch to inherently clean pipeline quality natural gas. The project "nets out" of PSD for all pollutants except VOC (a 56 ton annual increase), hence a BACT determination was completed.

The lower NO_X emissions will reduce ozone (smog) formation potential and nitrate fallout. The lower PM/PM_{10}, SO_2 and SAM emissions will reduce visible emissions, fine particulate generation, and acid smut fallout. Impacts due to the proposed project emissions are all favorable and the net effect is a "creation of available increment" in the PSD Class I (Everglades) 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).*

AAL 7/29/99

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

Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

aaf 7/29

"Protect, Conserve and Manage Florida's Environment and Natural Resources"

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Memorandum

Florida Department of Environmental Protection

TO: ~~C. H. Fancy~~ aaf for CHF

FROM: A. A. Linero AA Lin

DATE: July 29, 1999

SUBJECT: FPL Sanford 2200 MW Repowering Project
DEP File No. 1270009-004-AC

Attached is the draft public notice package including the Intent to Issue and the Technical Evaluation and Preliminary Determination for the Sanford Repowering Project. The application is for installation of eight (8) 250 megawatt (MW) combined cycle units to replace two (2) gas and residual oil-fired steam generators at the Sanford Plant.

Each unit is a 170 megawatt General Electric MS7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with existing gas and residual oil-fired units (872 MW total capacity) will be dismantled. The project also includes: a cooling tower for once-through brackish water; a small boiler or heaters to heat the natural gas prior to use; and two relatively short stacks per unit for simple and combined (with HRSG) operation.

Nitrogen Oxides (NO_X) emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of carbon monoxide (CO) will be controlled to 12 ppm, while emissions of volatile organic compounds (VOC) will be less than 1.4 ppm. Emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the switch to inherently clean pipeline quality natural gas.

There are very substantial emission reductions for all pollutants except VOC. The project netted out of PSD and no BACT was required. The lower NO_X emissions will reduce ozone (smog) formation potential and nitrate fallout. The lower PM/PM_{10}, SO_2 and SAM emissions will reduce visible emissions, fine particulate generation, and acid smut fallout. The overall effect of the project will be "creation of available increment" in the PSD Class II areas.

We will send copies to EPA and the Park Service and will consider their comments prior to issuance of the final permit. I recommend your approval of the attached Intent to Issue and the cover letter.

AAL/aal

Attachments