Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

May 28, 2004

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. H. O. Nunez, Plant General Manager
Florida Power & Light Company (FPL)
Turkey Point Fossil Plant
9700 Southwest 344 Street
Homestead, Florida 33035

Re: FPL Turkey Point Fossil Plant
DEP File No. 0250003-006-AC (PSD-FL-338)
1150 MW Combined Cycle Unit No. 5

Dear Mr. Nunez:

Enclosed are documents indicating the Department's intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to FPL for construction of a 1,150 megawatt combined cycle unit at the Turkey Point Fossil Plant. The documents include: the "Intent to Issue PSD Permit;" the "Public Notice of Intent to Issue PSD Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

The Public Notice must be published one time only as soon as possible in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes. Proof of publication, i.e., newspaper affidavit, must be provided to the Department's Bureau of Air Regulation office within seven (7) 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 other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

A. A. Linero

for Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/aal

Enclosures

"More Protection, Less Process"

Printed on recycled paper.

SENDER: *COMPLETE THIS SECTION*

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. H. O. Nunez
Plant General Manager
FPL Turkey Point Fossil Plant
9700 Southwest 344 Street
Homestead, FL 33035

COMPLETE THIS SECTION ON DELIVERY

A. Received by *(Please Print Clearly)* B. Date of Delivery

C. Signature

X ☐ Agent ☒ Addressee

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☒ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? *(Extra Fee)* ☐ Yes

2. Article Number *(Copy from service label)*
7099 3220 0003 6189 5273

PS Form 3811, July 1999 Domestic Return Receipt 102595-99-M-1789

U.S. Postal Service
CERTIFIED MAIL RECEIPT
(Domestic Mail Only; No Insurance Coverage Provided)

7099 3220 0003 6189 5273

Article Sent To:

Mr. H. O. Nunez, Plant Manager

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

Name (Please Print Clearly) (To be completed by mailer)
FPL Turkey Point Fossil Plant

Street, Apt. No.; or PO Box No.
9700 Southwest 344 Street

City, State, ZIP+ 4
Homestead, FL 33035

PS Form 3800, July 1999 **See Reverse for Instructions**

In the Matter of an
Application for Permit by:

Florida Power and Light Company (FPL)
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
Mr. H. O. Nunez, Plant General Manager

DEP File No. 0250003-006-AC
Draft Permit No. PSD-FL-338
FPL Turkey Point Fossil Plant
1,150 MW Combined Cycle Unit 5

INTENT TO ISSUE PSD PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD), copy of DRAFT Permit attached, for the proposed project as detailed in the application specified above and the attached Technical Evaluation and Preliminary Determination for the reasons stated below.

The applicant, FPL, applied on November 14, 2003 (deemed sufficient on April 7 2004) to the Department for a PSD permit for a 1150 megawatt combined cycle gas turbine project (Unit 5) at the FPL Turkey Point Fossil Plant located east of Homestead and Florida City on Biscayne Bay, Miami-Dade County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), 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 a PSD permit is required.

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

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

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. 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 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.

This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3).

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

for Trina L. Vielhauer, 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 5/28/04 to the persons listed:

H. O. Nunez, FPL*
Mayor, Miami-Dade County
Mayor, City of Homestead
Mayor, Florida City
John Benjamin, Everglades National Park
Linda Canzanelli, Biscayne National Park
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Steven L. Palmer, DEP Siting Office
Tom Tittle, DEP SED
Paul Darst, Department of Community Affairs
Chair, Miami-Dade County EQCB
H. Patrick Wong, Miami-Dade County DERM
Ken Kosky, P.E., Golder
Barbara Linkiewicz, FPL

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.

Victoria Gibson 5/28/04
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 0250003-006-AC (PSD-FL-338)

FPL Turkey Point Fossil Plant, New Combined Cycle Unit 5
Miami-Dade County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to the Florida Power & Light Company. The permit is one of several authorizations needed to construct a nominal 1,150 MW combined cycle natural gas-fired unit at the existing Turkey Point Fossil Plant east of Homestead and Florida City, and adjacent to Biscayne Bay in Miami-Dade County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's corporate address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

The applicant proposes to construct a new electrical power generating unit (Unit 5). The primary components are: four combustion turbine-electrical generators; four supplementary-fired heat recovery steam generators (HRSGs); a single steam-electrical generator; a 22-cell mechanical draft cooling tower; four exhaust stacks; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment.

Unit 5 will be permitted to operate continuously while firing inherently clean natural gas. Ultra low sulfur (0.0015 percent sulfur) distillate fuel oil will be available in Southeast Florida by the time the project starts up. Its use will be allowed as backup fuel for 500 hours per year per combustion turbine. Steam injection into the combustion turbines (power augmentation) and firing of natural gas in the duct burners located within the HRSGs (supplemental firing) will be allowed for limited periods of time to meet peak power demand.

A selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with Dry Low-NO_X combustion (gas firing) and wet injection (oil firing) to control NO_X emissions. The proposed NO_X emission limit of 2.0 parts per million by volume, dry corrected to 15 percent oxygen (ppmvd @15% O_2) of NO_X while firing natural gas represents the most protective standard for any project authorized to date in the Southeastern United States. Sufficient catalyst will be used to minimize emissions of ammonia reagent. The proposed NO_X limit while firing ultra low sulfur fuel oil is 8 ppmvd @15% O_2. The proposed CO emission limits of 4.1 and 8.0 ppmvd @15% O_2 while burning gas and oil respectively represent the lowest values guaranteed to-date without requiring oxidation catalyst. Typical CO emissions will actually be 2 ppmvd or less under most operational modes.

Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient, high-temperature combustion of inherently clean fuels. Emissions of CO and NO_X will be continuously monitored to demonstrate compliance with the conditions of the permit. The complete set of proposed emission limits is available at the Department offices, the local Miami-Dade County DERM office and website addresses indicated below.

The applicant's estimate of maximum potential annual emissions from Unit 5 are summarized in the following table.

Pollutant	Maximum Tons Per Year	PSD Significant Emission Rate Tons Per Year	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NO_X	312	40	Yes
PM/PM_{10}	420/229	25/15	Yes
SO_2	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park (i.e. PSD Class II Areas) Therefore; multi-source modeling was not required for ambient air quality standards Class II increments. The predicted impacts in the Class I Everglades National Park (ENP) are less than the applicable significant impact levels except for the 3-hour and 24-hour SO_2 and 24-hour PM_{10} impacts. Therefore multi-source increment modeling was required for the 3–hour and 24-hour SO_2 and 24-hour PM_{10} impacts upon the ENP. The following table summarizes the maximum predicted 3-hour and 24-hour SO_2 and 24-hour PM_{10} increment consumption by the new project and by all project in the general area since 1977.

	PM_{10} Increment Consumed in ug/m^3 and % at ENP		SO_2 Increment Consumed in ug/m^3 and % at ENP	
Averaging Time	By Project	All Sources	By Project	All Sources
24-hour	0.5 (10% of Allowable)	2.1 (42% of Allowable)	0.4 (8% of Allowable)	4.1 (82% of Allowable)
3-hour	No Analysis Required	No Analysis Required	2 (8% of Allowable)	18 (72% of Allowable)

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. A small impact on air quality related values (visibility) was projected to occur approximately 2 days in three years if ultra low sulfur fuel oil is continuously fired, instead of natural gas, and the ambient temperature is 35 degrees F. Because fuel oil will be used less than 10 percent of the time and such low temperatures are atypical for the South Florida coastline, the coincidence of the factors that promote visibility impact is minimal. The probability of such an occurrence is less than one every three years.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If 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. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

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

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

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

Department of Environmental Protection Bureau of Air Regulation 111 S. Magnolia Drive, Suite 4 Tallahassee, Florida 32399-2400 Telephone: 850/488-0114 Fax: 850/922-6979	Department of Environmental Protection Southeast District Office 400 North Congress Avenue West Palm Beach, FL 33416-5425 Telephone: 561/681-6600 Fax: 561/681-6790	Miami-Dade Department of Environmental Resource Management 33 SW 2nd Avenue, Suite 900 Miami, Florida 33130-1540 Telephone: 305/372-6925 Fax: 305/372-6954

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact A. A. Linero or Debbie Nelson of the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114 for additional information. Address e-mail comments to alvaro.linero@dep.state.fl.us . The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/air/permitting/construction/turkeypoint.htm .

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power and Light Company
FPL Turkey Point Fossil Plant

1,150-Megawatt Combined Cycle Power Project

Miami-Dade County

DEP File No. 025003-006-AC (PSD-FL-338)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section

May 28, 2004

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power and Light Company
9700 Southwest 334th Street
Homestead, Florida 33035

Authorized Representative:
H.O. Nunez, Plant General Manager

Processing Schedule

- Received Site Certification and PSD application on November 14, 2003;
- Additional information requested via Power Plant Siting Office on January 20, 2004;
- Received additional information on March 1, 2004;
- Siting Application Found Sufficient on April 7, 2004;
- Intent to Issue PSD Permit distributed May 28, 2004.

Facility Description and Location

The Florida Power and Light (FPL) Company operates the Turkey Point Fossil Plant, which is located south of Miami, east of Homestead and Florida City and adjacent to Biscayne Bay, in Miami-Dade County. The existing Turkey Point Fossil Plant consists of two fossil fuel-fired steam electrical generating units and five "Black Start" diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The location of the Turkey Point Fossil Plant is shown in Figures 1 and 2.

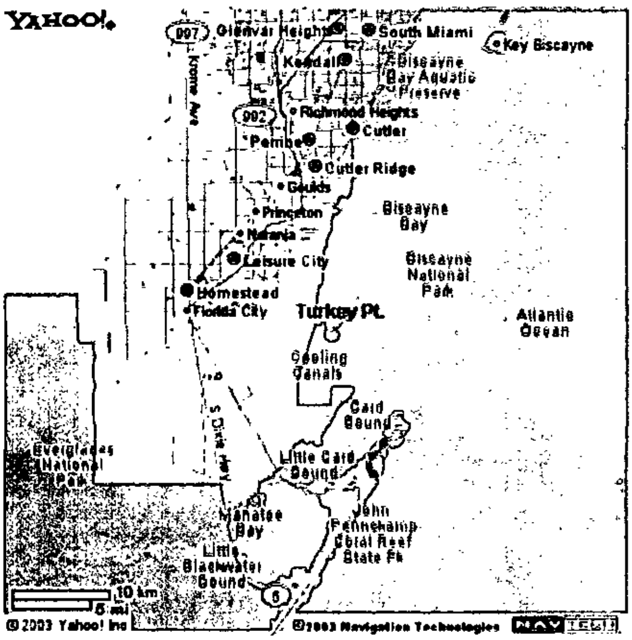

Figure 1. Location of Turkey Point

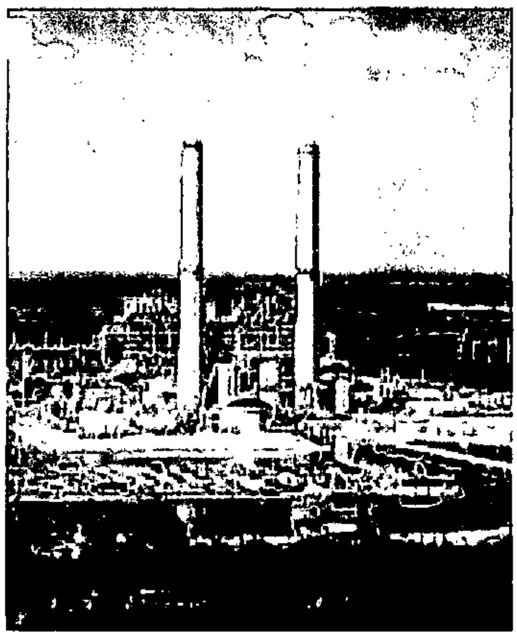

Figure 2. Turkey Point Fossil Plant

The Turkey Point Fossil Plant is located generally east of the Class I Everglades National Park and is approximately 20 kilometers northeast of the nearest boundary to the park. Biscayne National Park encompasses the general area to the east of the plant.

Regulatory Categories

Title III: The facility is a "Major Source" of hazardous air pollutants (HAPs). Based on the available information, the project is potentially subject to at least one National Emission Standard for Hazardous Air Pollutants (NESHAP) and the applicable Maximum Achievable Control Technology (MACT).

Title IV: The facility operates units subject to the Acid Rain provisions of the Clean Air Act.

Title V: The facility is a Title V or "Major Source" of air pollution because the potential emissions of at least one regulated pollutant exceed 100 tons per year or because it is a Major Source of HAPs. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The facility is located in an area that is in attainment with, or designated as unclassifiable for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a fossil fuel-fired steam electric plant, which is one of the 28 PSD Major Facility Categories identified in Table 62-212.400-1, F.A.C. Emissions from the facility are greater than 100 tons per year for at least one regulated pollutant. Therefore, the facility is a Major Facility with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The facility is a steam electrical generating plant. The project will result in more than 75 MW of steam-generated electrical power and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "4-on-1" combined cycle unit (Unit 5) consisting of the following equipment and specifications: four 170 MW gas turbine-electrical generator sets; four gas-fired heat recovery steam generators (550 mmBtu/hour); four exhaust stacks between 130 and 150 feet in height; a common steam-electrical generator (470 MW); a 22-cell mechanical draft cooling tower; a 4.3 million gallon diesel fuel storage tank; and other associated support equipment. Gas turbines are also called combustion turbines.

Gas Turbine/HRSG Units: Each gas turbine/HRSG unit consists of a nominal 170 MW General Electric 7FA gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, and a supplementary gas-fired heat recovery steam generator (HRSG). Following are additional project characteristics.

- Fuels: Each gas turbine will fire natural gas as the primary fuel and *ultra low sulfur* (0.0015% Sulfur) distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests 500 hours per year per gas turbine (or equivalent) for oil firing.
- Generating Capacity: Each of the four gas turbines has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Each of the four heat recovery steam generators (HRSGs) provides steam to the single steam turbine electrical generator, which has a nominal capacity of 470 MW. The total nominal generating capacity of the "4-on-1" combined cycle unit is 1150 MW.

- Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and restricting the amounts of ultra low sulfur distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: Each gas turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitors as well as CO monitors are employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: Each heat recovery steam generator has a combined cycle stack (HRSG stack) that is at least 130 feet tall with a nominal diameter of 19 feet. The following summarizes the exhaust characteristics:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	1608 mmBtu/hour	59° F	202° F	1,023,872
Oil	1830 mmBtu/hour	59° F	295° F	1,224,407

Project Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressors of the GE 7FA combustion turbines proposed for this project. The air is compressed by a pressure ratio of about 15 times atmospheric pressure. A portion of 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.

The hot combustion gases are then diluted with additional cool air from the compressor and directed to the turbine section at temperatures of approximately 2600 °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. Turbine exhaust gas is discharged at a temperature greater than 1100 °F and high excess oxygen and is available for additional energy recovery.

All units will ultimately operate in combined cycle mode in which the combustion turbine drives an electric generator while the exhausted gases are used to raise additional steam in a heat recovery steam generator (HRSG). The steam, in-turn, drives a separate steam turbine-electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent.

Figure 3 is a simplified diagram of combined cycle operation.

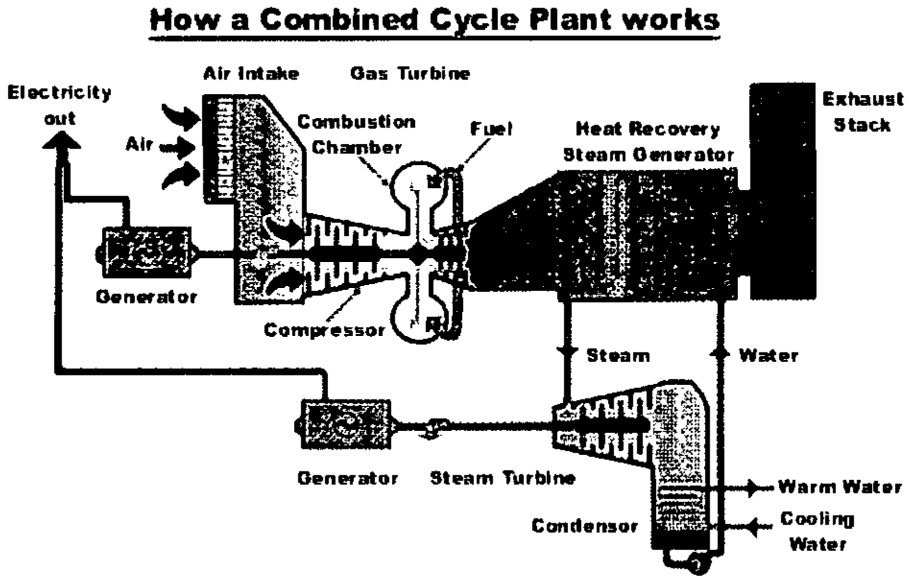

Figure 3. Key Components of a Combined Cycle Unit

The applicant has also requested the following modes of operation within the normal combined cycle operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging will be implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2880 hours of duct burning per year for each gas unit.
- High Power Modes (HPM): These include Power Augmentation (PA) and Peaking (PK). Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PK is based on greater fuel use and combustion turbine temperatures resulting in greater power production. PA and PK can cause greater uncontrolled NO_X emissions. PA causes greater uncontrolled CO emissions while PK theoretically causes less CO emissions. The applicant requests 400 hours of HPM for each unit and only when using the Duct Burners.

Further process details are provided in the Draft determination of Best Available Control Technology (BACT) in Section 4.0 below.

Potential Emissions

The project will result in emissions of carbon monoxide (CO), lead (Pb), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist (SAM), and volatile organic compounds. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines, duct burners, and cooling tower).

Table 1. Applicant's Estimated Annual Emissions

Pollutant	Project Emissions TPY	PSD Significant Emission Rate, TPY	PSD Review Required?
CO	464	100	Yes
Pb	0.026	0.6	No
NO_X	312	40	Yes
PM/PM_{10}	420/229	15/25	Yes
SO_2	193	40	Yes
SAM	19	7	Yes
VOC	68	40	Yes

3. RULE APPLICABILITY

State Regulations

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

Chapter	**Description**
62-4	Permitting Requirements
62-17	Electrical Power Plant Siting
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Miami-Dade County Code of Ordinances

Chapter	**Description**
24 - II	Air Quality
24.41.1	Prohibitions against Air Pollution (Ringleman)
24.41.3	Sulfur Dioxide (Liquid Fuel Sulfur Dioxide Emissions)
24.41.6	Storage and Handling of Petroleum Products (Reid Vapor Pressure)

Federal Regulations

This project is also subject to certain applicable federal provisions regarding air quality as established by the EPA in the Code of Federal Regulations (CFR) and summarized below.

Title 40	Description
Part 60	New Source Performance Standards (NSPS)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain - Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions

Note: Acid rain requirements will be included in the Title V air operation permit.

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as defined in Rule 62-212.400, F.A.C. A PSD review is only required in areas that are currently in attainment with the National Ambient Air Quality Standard (AAQS) for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

- 250 tons per year or more of any regulated air pollutant, or
- 100 tons per year or more of any regulated air pollutant and the facility belongs to one of the 28 Major Facility Categories (Table 62-212.400-1, F.A.C.), or
- 5 tons per year of lead.

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates (SERs) listed in Table 62-212.400-2, F.A.C. For each significant pollutant exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for NO_X, CO, VOC, SO_2, SAM and PM/PM_{10}.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Rule 62-210.200 (definitions), FAC as follows:

"Best Available Control Technology" or "BACT" - An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which

the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

a. *If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of an emissions unit or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.*

b. *Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.*

According to Rule 62-212.400(5)(h), FAC, the applicant must at a minimum provide certain information in the application including:

3. *A detailed description of the system of continuous emissions reduction proposed by the facility or modification as BACT, emissions estimates and any other information as necessary to determine that BACT would be applied to the facility or modification;*

According to Rule 62-212.400(6), FAC, in making the BACT determination, the Department shall give consideration to:

1. *Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).*
2. *All scientific, engineering, and technical material and other information available to the Department.*
3. *The emission limiting standards or BACT determinations of any other state.*
4. *The social and economic impact of the application of such technology.*

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.

4.2 NO_X BACT Determination

Nitrogen Oxides Formation

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

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

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, lowers achievable thermal efficiency for the unit.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 4 which is from a General Electric discussion on these principles.

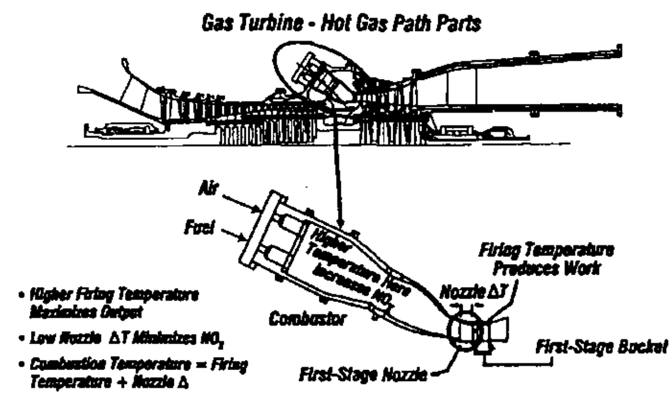

Figure 4 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important for natural gas-fired projects such as this FPL project.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the FPL project. The proposed NO_X controls will reduce these emissions significantly. For reference, the New Source Performance Standard (40 CFR 60, Subpart GG) for NO_X emissions from large utility gas turbines such as the GE7FA is approximately 105 ppmvd @15%O_2. This constitutes the legal floor (absolute maximum NO_X value) in a "Top/Down" BACT determination.

<u>Descriptions of Available NO_X Controls</u>

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls: Dry Low NO_X (DLN)

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 incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 5.

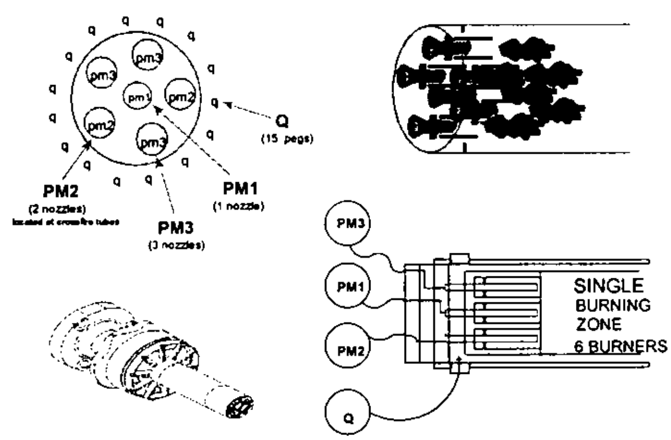

Figure 5 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability.

<u>Design</u> emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 6 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station. The combustor can be tuned differently to achieve emissions as low as 9 ppm of NO_X. Actual emissions of CO and VOC are actually much less than suggested by the diagram. However the diagram also suggests the need to minimize operation at low load conditions.

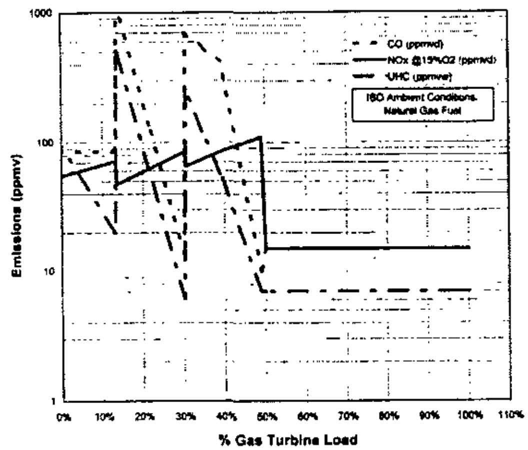

Figure 6 – Emissions Characteristics for DLN-2.6 (if tuned to 15 ppmvd NO_X)

The combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur 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.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.

Table 2. Test Results for GE 7FA Gas Turbine, TECO Polk Power (Simple Cycle) [1]

Percent of Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1

Following are the results for testing of the GE7FA combined cycle unit at the City of Tallahassee Purdom Plant.

Table 3. Test Results for GE 7FA Gas Turbine, City of Tallahassee's Purdom Station [2]

Percent of Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd
70	7.2	ND
80	6.1	ND
90	6.6	ND
100	8.7	0.85

The test results at the TECO and Tallahassee projects confirm NO_X, CO, and VOC emissions substantially less than typical guarantees as discussed below.

An important consideration is that power and efficiency are sacrificed in the effort to achieve low NO_X by combustion technology. This limitation is seen in Figure 7 from an EPRI report.[3] Developments such as single crystal blading, aircraft compressor design, high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 7.

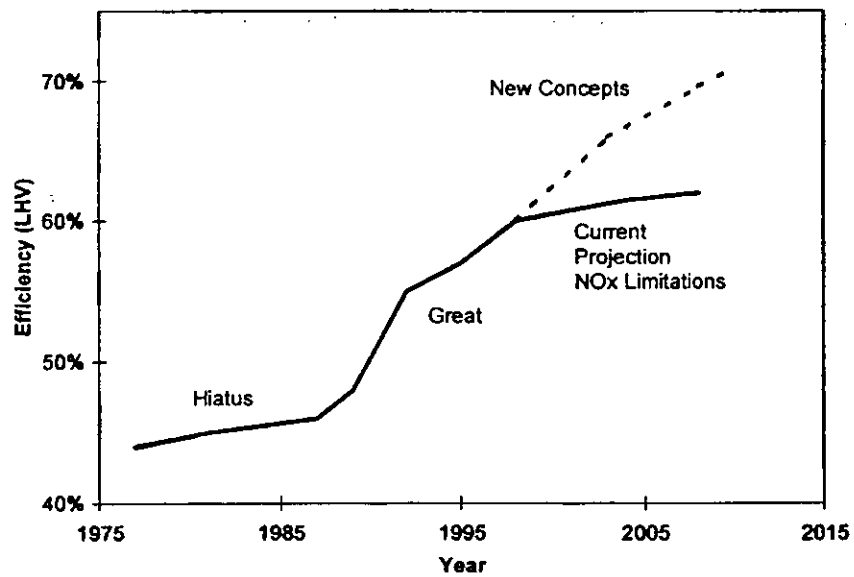

Figure 7 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned by FPL. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 1). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

Numerous 7FA units with DLN technology for NO_X control have been installed in Florida and throughout the United States with guarantees of 9 ppmvd. This represents a reduction of approximately 95 percent compared with uncontrolled emissions and a reduction greater that 90 percent compared with the previously mentioned NSPS limit of approximately 105 ppmvd.

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).[4] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

DLN is technically possible for fuel oil, but requires a very large and expensive atomization rig and is feasible only where water is virtually unavailable. Therefore, dual fuel combustors employ wet injection to reduce NO_X emissions when firing fuel oil as discussed above.

Catalytic Combustion - XONON™

Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[5] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

There has been increased interest in catalytic combustion as a result of technological improvements and incentives to reduce NO_X emissions without the use of add-on control equipment and reagents.

Catalytica has developed a system know as 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 production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[6] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation.[7] By now, five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[8] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

It is difficult to apply XONON on large units because they require relatively large combustors and would not likely deliver the same power as a unit relying on conventional diffusion flame or lean premixed combustion. This technology is not feasible at this time for the FPL Turkey Point project.

Selective Catalytic Reduction (SCR)

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 becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

Kissimmee Utilities Authority (KUA) installed an SCR system at the Cane Island Unit 3 project. The KUA project complies with a limit of 3.5 ppmvd with a combination of DLN and SCR. Permits were issued to Competitive Power Ventures (CPV), Calpine, Progress Energy, and Tampa Electric to achieve 3.5 ppmvd. More recently, permits were issued to El Paso Merchant Energy Company for facilities in Broward, Manatee and Palm Beach counties and to CPV for its Pierce facility with a limit each of 2.5 ppmvd @15% O_2 by SCR. Similarly permits were issued in 2003 to FPL for projects in Manatee and Martin County each with a limit of 2.5 ppmvd @15%O_2 by SCR.

Figure 8 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 9 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

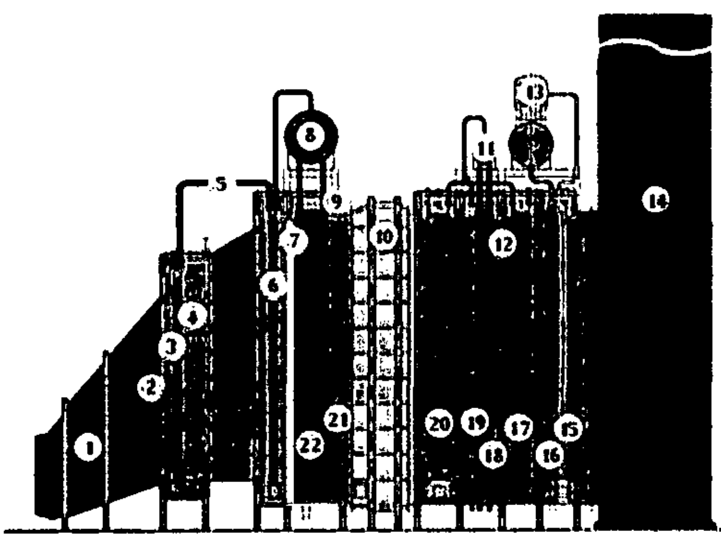

Figure 8 – Key HRSG Components (10 is SCR)

Figure 9 – PGN Hines Block I

If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Obviously this is not a problem with natural gas or ultra low sulfur distillate fuel oil. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst.

The catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[9] The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 4. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[10]

% Full Load	NO_X, ppmvd @15% O_2	CO, ppmvd	VOC, ppmvd	NH_3 ppmvd
50	1.4 – 1.7	0.5 – 0.8	0.2 – 0.4	0.08 – 0.2
75	1.5 – 1.6	< 0.1	0.2 - 0.4	0.02 – 0.06
87	1.4 – 1.7	~ 0 – 0.3	0.1	0.05 – 0.1

It is noteworthy as well that the low NO_X emissions were achieved with minimal ammonia (NH_3) emissions. It would be reasonable to expect the ammonia emissions to increase over time to the guaranteed value of 2.0 ppmvd. The project employed Englehard oxidation catalyst for CO and VOC control. In the previous examples, it is noted that the GE 7FA achieved similarly low values throughout the same load range without oxidation catalyst.

SCR is a commercially available, demonstrated control technology currently employed on numerous large combined cycle combustion turbine projects permitted with very low NO_X emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in further NO_X reduction of 60 to 95% after initial control by DLN or WI in a combined cycle unit or total control on the order 95 to 99%.

SCONO$_X$™

This technology is an NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power was the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[11] Alstom Power was not successful in marketing the product at large facilities.

SCONO$_X$™ technology (at 2.0 ppmvd) was been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas. SCONOx™ has demonstrated achievement of lower values (< 1.5 ppmvd) in a small (32 MW) system. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. Basically, SCONO$_X$™ can match the performance of SCR without ammonia slip. On the other hand, the catalyst must be intermittently regenerated while on-line through the use of hydrogen produced on-site from natural gas reforming unit.

Table 5 contains averaged cost values for $SCONO_X$™ and SCR developed by the California Air Resources Board for their Legislature.[12] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 5. Cost Comparison between SCR and $SCONO_X$ for a 500-MW Unit

Capital Cost ($)		Annual O&M Cost ($)	
SCR/CO	$SCONO_X$™	SCR/CO	$SCONO_X$™
6,259,857	20,747,637	1,355,253	3,027,653

The cost of an oxidation catalyst for CO control is included with the SCR system for comparable evaluation with $SCONO_X$™ multi-pollutant reduction capabilities. Cost figures show that the SCR/oxidation catalyst package costs less than the $SCONO_X$™ system. The report cautions that the values should be used only for relative comparison and not intended for use in detailed engineering.

Estimates provided by FPL for the proposed 1,150 MW project claim even greater cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that $SCONO_X$™ is not cost-effective for the present project.

Applicant's NO_X BACT Proposal

The applicant originally proposed a BACT NO_X limit of 2.5 ppmvd @15% O_2. FPL proposed to meet the BACT emission while burning natural gas by a combination of DLN technology and SCR. FPL proposed a BACT NO_X emission limit of 10 ppmvd @15% O_2 while burning backup ultra low sulfur fuel oil by a combination of wet injection and SCR.

Since that time, FPL agreed to lower limits as follows:

a. Gas Firing: 2.0 ppmvd @ 15% O_2, 24-hour average

b. Oil Firing: 8.0 ppmvd @ 15% O_2, 24-hour average

Department's Draft NO_X BACT Determinations

Table 6 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average.

The Department agrees that FPL's proposal of 2.0 ppmvd @15% O_2 on a 24-hour basis and minimization of fuel oil use represents BACT for this project. The limits of 2.0 and 8.0 ppmvd @15% O_2 represent reductions of 98% and 92% for the gas and oil cases respectively when compared with the applicable New Source Performance Standard at 40 CFR 60, Subpart GG.

Table 6. Recent NO_X Standards for "F-Class" Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2 and Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 - FO	4x170 MW GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 - FO	4x170 MW GE 7FA & DBs
PGN Hines III, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
El Paso Manatee, FL	250	2.5 – NG (24-hr)	175 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs
Enron/Ft. Pierce, FL	~250	3.5 – NG (3-hr) 10 - FO	170 MW MHI 501F

Notes: NG = Natural Gas DB = Duct Burner PA = Power Augmentation
FO = Fuel Oil GE = General Electric WH = Westinghouse ABB = Asea Brown Bovari

4.3 CO and VOC BACT Determination

CO and VOC Formation and Control Options

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

Despite the relatively high BACT limits typically proposed when using combustion controls, much lower emissions are typically reported for very large combustion turbines (at least at full load operation) without use of oxidation catalyst.

Based on testing discussed in the NO_X technology section above, GE 7FA units achieved CO emissions in the range of 0.3 to 1.6 ppmvd (new and clean) when firing gas at the City of Tallahassee Purdom Unit 8 and the TECO Polk Power Station Unit 2 at loads between 50 and 100 percent. This level of performance has been corroborated by recent tests at numerous new projects throughout the state. Notably, the emissions of the GE7FA units without oxidation catalyst matched those of the ABB units at ANP Blackstone that were equipped with oxidation catalyst.

Similarly, VOC emissions less than 1 ppm have consistently been measured at new GE7FA units throughout the state. Again the results are roughly equal to those at ANP Blackstone.

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[13] The following statement was taken from the report:

"GE is offering CO guarantees of 5 ppmvd for the GE PG7241FA DLN on a case-by-case basis following a detailed evaluation of the situation - thus validating its position that oxidation catalysts are not economically justified for CO emissions reduction for the GE PG7241FA DLN units while firing natural gas."

The following figure from GE's article is consistent with the data collected by the Department and supports the Department's analysis of this technical issue.

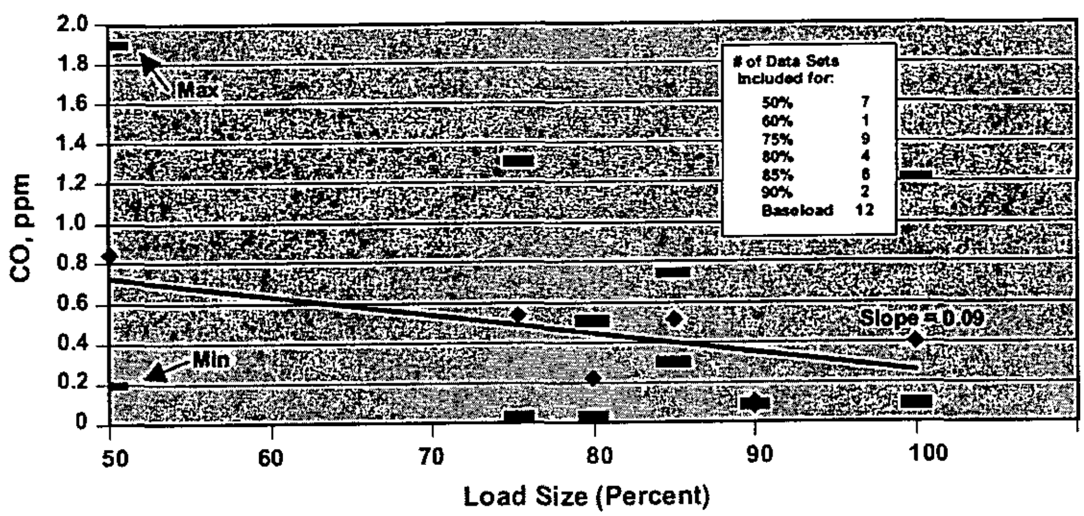

Figure 10. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

Duct Burner, HPM, Low Load and Fuel Oil Considerations

The presence of a duct burner (refer to Figure 8, Component 4) and possibility of other high power modes (HPM) including power augmentation (PA) and peaking (PK) complicate the evaluation somewhat.

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O_2). In the design shown in Figure 8, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 11 and 12 are of an individual burner and an array comprising a duct burner. The hot TEG serves as combustion air for gas introduced into the burner array.

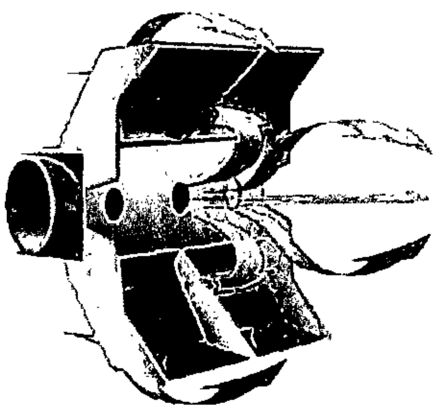

Figure 11 – Individual Burner (Coen)

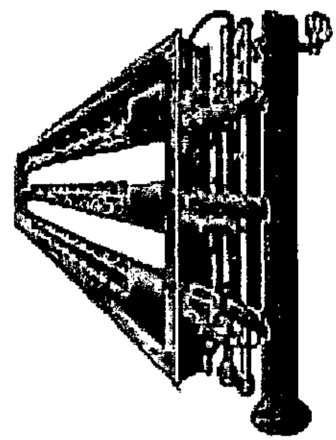

Figure 12 – Burner Array (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC and CO control because of destruction by the duct burner.[14] Basically, the claim is that a "3 on 1" configuration (3 CT's & 1 HRSG) producing 750 MW can be replaced with a "2 on 1" configuration by adding very large Coen "Power Plus" DBs in a Nooter Eriksen HRSG and still produce 750 MW. Basically the capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided.

Following is a table with the results of CO and VOC testing recently completed at the Gulf Power Lansing Smith Plant.[15] The units tested were GE7FA combustion turbines (CT) of the same type that FP&L will install at the Manatee Power Plant. Tests were conducted on each combustion turbine while using duct burners (DB).

Table 7. CO and VOC Emissions - Gulf Power Plant Smith GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
Gulf Smith Unit 4 (CT & PA)	5.18	0.61
Gulf Smith Unit 5 (CT & PA)	8.61	0.38

As seen from Table 7, emissions of CO and VOC are very low when the DBs are used and without PA. The values under the DB mode are roughly the same as those for the normal operation mode (no DB or PA) in Tables 2 and 3 above.

The Gulf Smith units also provide an example of power augmentation (PA) with the duct burners (DB) off. Emissions when employing PA are clearly greater than the base case in Tables 2 and 3 and greater than the DB case.

Following is a table with results of CO and VOC emissions from GE 7FA units at Alabama Power's Plant Barry when operating simultaneously in DB and PA modes.[16]

Table 8. CO and VOC Emissions - Alabama Power Plant Barry GE 7FA Units (lb/mmBtu)

Unit (Modes)	CO	VOC
Barry Unit 7A (CT & DB & PA)	0.018 (< 9 ppmvd@15% O_2)	0.000 (< 1 ppmvd@15% O_2)
Barry Unit 7B (CT & DB & PA)	0.008 (< 4 ppmvd@15% O_2)	0.000 (< 1 ppmvd@15% O_2)

Comparison of the results from the Gulf Power and Alabama Power units suggests that the PA mode increases CO emissions whether or not the duct burners are used, while VOC emissions remain low.

Recently, the Department received additional information regarding tests conducted at the recently commissioned Southern/KUA/OUC/FMPA project located at the OUC Stanton Facility. The two units are equipped with ducts burners and practice power augmentation. Following are the results of those tests.[17]

Table 9. Emissions from Stanton A Combined Cycle GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	NO_X	CO	VOC	NH_3
Unit 25 (CT)	2.5	0.5	0.04	0.2
Unit 25 (CT & DB)	2.5	1.6	0.2	0.4
Unit 25 (CT & PA)	3.1	8.3	1.7	0.9
Unit 26 (CT)	3.1	0.5	0.49	0.1
Unit 26 (CT & DB)	3.2	1.6	0.26	0.5
Unit 26 (CT & PA)	2.7	6.7	0.8	0.9

The results from Stanton A add further credence to the hypotheses that CO and VOC emissions are low when using duct burners and are greatest when practicing power augmentation.

According to information from General Electric, CO emissions during PK will actually be less than during normal operation while NO_X emissions will increase. This is because of higher flame temperature in the combustors during PK compared with normal operation.[18] The projections regarding NO_X were confirmed recently at an FPL facility.[19] Baseline NO_X emissions (DLN control only) increased from 7 to 9.6 ppmvd @ 15% O_2, while power production from the CT-electrical generator increased by 3 or 4 MW. No tests were reviewed by DEP to confirm the CO emissions reduction effect of PK.

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in the Table below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_X control is practiced on all such units when firing fuel oil.

Table 10. CO, VOC Test Results. GE 7FA Gas Turbines firing Fuel Oil. (ppmvd @15% O_2)

Facility/Unit (load %)	CO	VOC
Martin Unit 8A (100%)[20]	0.6	0.4
Martin Unit 8B (100%)	0.8	0.4
Purdom Unit 8 (~50%)[21]	1.2	
Purdom Unit 8 (100%)	1.3	
TECO Polk Unit 3 (100%)	0.6	0.1
JEA Kennedy KCT-7 (100%)[22]	2.1	1.1
Stanton A – Unit 25 (100%)	1.0	1.1
Stanton A – Unit 26 (100%)	1.0	0.8
Reliant Osceola Unit 1 (100%)[23]	0.04	0.18
Reliant Osceola Unit 2 (100%)	0.02	0.01
Reliant Osceola Unit 3 (100%)	0.54	0.00
Oleander Power Unit 1 (100%)	1.8	< 0.7
Oleander Power Unit 2 (100%)	1.1	< 0.7
Oleander Power Unit 3 (100%)	3.8	< 0.7
Oleander Power Unit 4 (100%)	2.7	< 0.7

The Department did not compare the manner in which water or steam is introduced into the CT during wet injection versus power (steam) augmentation to explain why the CO results from the two modes are different. The Department concludes that the low CO and VOC emissions while burning fuel oil constitute an empirical observation just as the high CO emissions during the PA mode also constitute an empirical observation.

One final observation is that CO and VOC emissions were low during a recent test of a GE 7FA combined cycle unit while firing fuel oil and using a gas-fired duct burner. The results are given in the following table.

Table 11. Emissions from GE 7FA CT - Fuel Oil & Gas-Fired Duct Burner (ppmvd @15% O_2)

KUA 3/Mode[24]	NO_X	CO	VOC	NH_3
CT & DB & FO	15	1.4	0.1	1.5

FP&L does not propose fuel oil firing while using gas-fired duct burners, but the results are instructive because even this unusual case yields low CO, VOC, and even NH_3 emissions.

The Department provided the information from the research summarized above to GE and FP&L. As a result, FP&L was able to obtain a guarantee for the FO case of 8 ppmvd @15% O_2.

El Paso was required to install oxidation catalyst at permitted but deferred (or cancelled) combined cycle projects using GE7FA CTs in Broward, Palm Beach, and Manatee Counties. The purpose of the catalyst for those projects is to limit CO emissions during continuous PA as opposed to the infrequent power augmentation (< 400 for sum of PA and PK) planned by FPL for the Turkey Point Unit 5 project.

Another consideration is "low load" operation. Several operators in Florida installed, will install, or are considering installing oxidation catalyst because: the supplier could not guarantee low CO emissions at medium loads (50 to 70 percent); the units actually exhibited high emissions at such loads; or the units required very long warm-up periods under low load (< 50% and very high CO) conditions.

These include Lakeland McIntosh Unit 3, Seminole Payne Creek, Enron Fort Pierce (deferred), and Progress Energy Hines Power Block II. This is in contrast to the GE 7FA units that exhibit low CO emissions at 50 percent.

Determinations CO, VOC, and PM/PM_{10} Emission Limit Determination

The following table is a list of recent CO and VOC (and PM) determinations for project throughout the country. FPL's proposal is included for comparison.

Table 12. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO - ppmvd (@15% O_2)	VOC - ppmv (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	1.0	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	1.0 (DB off) 1.7 (DB on))	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	1.0 (DB off) 2.0 (DB on))	0.01
Duke Morro, CA	2.0 (Ox-Cat)	1.15 (DB off) 2.0 (DB on)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	1.4	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	1.0 (DB off) 1.64 (DB on))	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL **(applicant proposal)**	4.1 – NG (DB off) 7.6 – NG (DB on) 14.1 – NG (DB+PA) 8.0 – FO	1.3 – NG (DB off) 1.9 – NG (DB on) 2.2 – NG (DB+PA) 2.8 – (FO)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	3 – 7.5 lb/hr	0.011
Calpine OEC, PA	10 (1-hr)	1.8	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	1.2	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	1.3 – NG (DB off) 4.0 – NG (DB, PA)	10% Opacity NH_3 = 5
PGN Hines III, FL	10 - NG (3.5 if Ox-Cat) 20 – FO (7 if Ox-Cat)	2 – NG 10 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	1.1 - NG	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	0.00126 lb/mmBtu	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	2.2 - NG 16 – Low Load 10 - FO	10% Opacity

Notes:
FO = Fuel Oil; NG = Natural Gas; GE = General Electric; DB = Duct Burner; WH = Westinghouse; PA = Power Augmentation; ABB = Asea Brown Bovari

Applicant's CO and VOC BACT Proposal

In response to comments by EPA and data provided by the Department, FPL obtained CO emission guarantees of 4.1 and 8.0 ppmvd @15% O_2 when firing natural gas and fuel oil respectively. These values represent the lowest guarantees yet without the need for oxidation catalyst. The applicant's revised BACT proposal is as follows:

Table 13. FPL Proposed BACT Emissions Limits for CO and VOC (@ 59 °F)

Modes	Hours (Max)	CO (ppmvd @15% O_2	VOC (ppmvd @15% O_2)
Gas Firing	8,760	4.1	1.3
Gas & DB	2,880	7.6	1.9
Gas & DB & HPM (PA/PK)	400	14.1/11	2.2
Fuel Oil Firing	500	8.0	2.8

Department's CO and VOC BACT Proposal

Based on the data available to the Department, FP&L's respective proposed CO emission limits for normal operation and fuel oil firing of 4.1 and 8.0 ppmvd @ 15% O_2 are acceptable. A detailed cost assessment would reveal that the cost to achieve lower CO emissions by installation of oxidation catalyst is not warranted. This cost has been estimated by General Electric at approximately $8,000 per ton. While the Department does not necessarily accept the GE estimate, oxidation catalyst would not be cost-effective.

There will be considerable use of duct burners (DB). Although the Department believes CO emissions under DB in terms of ppmvd @15% O_2 will be approximately equal to emissions under the normal mode, the requested value of 7.6 ppmvd @15% O_2 is acceptable. This provides for a margin of uncertainty because the manufacturer of the DB assumes that the burner does create some CO and adds to that generated in the CT. Requirement of oxidation catalyst could reduce that uncertainty, but would not be cost effective given the tonnage removed for the cost and the empirical observation that emissions will actually be low (~ 2 ppmvd @15% O_2).

The High Power Modes (HPM) of Power augmentation (PA) and peaking (PK) are low probability scenarios that will occur for only 400 hours per CT and only in conjunction with use of the duct burners. The requested values of 11 and 14.1 ppmvd @ 15% O_2 are acceptable for PK and PA respectively in conjunction with DB.

The Department will set a continuous 24-hr CO limit of 8.0 ppmvd to be comprised of all firing modes and durations with the exception of simultaneous DB & PA, which will be subject to a separate limit of 14.1 ppmvd @15% O_2. Stack testing will still be required to demonstrate compliance with the guaranteed values for the key normal, fuel oil and duct burner modes.

Similarly, the Department accepts FP&L's proposals for VOC emission limits. It is noted that total VOC emissions will be only 68 TPY combined from the four combustion turbines. The test data reviewed by the Department indicate that actual emissions are likely to be less than the PSD significant emission rate of 40 TPY. The BACT values provide a small margin of safety that assures compliance.

4.4 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM) BACT Determination

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.

Basically the use of low sulfur fuels simply means that the sulfur reduction was accomplished to very low levels at the refinery or gas conditioning plant prior to distribution.

For this project the applicant has proposed as BACT the use of ultra low sulfur fuel oil (0.0015 percent sulfur) and clean natural gas with a sulfur fuel specification less than 2 grains of sulfur per 100 standard cubic feet of natural gas ($\leq$ 2 gr/100 SCF). This will be the first project in the state required to use the cleanest fuel oil scheduled to be available by the time the new unit begins operation. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8% by weight.

The applicant estimated total emissions for the project at 193 tons per year of SO_2 and 19 tons per year of sulfuric acid mist. The Department accepts FP&L's BACT proposal for SO_2 and SAM.

4.5 Particulate Matter (PM/PM_{10}) BACT Determination and Ammonia (NH_3) Control

PM/PM_{10} Formation and Control Options

PM and PM_{10} are emitted from combustion turbines due to incomplete fuel combustion. They are minimized by use of clean fuels and good combustion.

Natural gas and ultra low sulfur distillate fuel oil will be the only fuels fired and are efficiently 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 ultra low sulfur fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

The following table is a summary of PM_{10} emissions provided by General Electric to FP&L from GE 7FA units operating on natural gas or fuel oil.[25, 26]

Table 14. PM_{10} Emissions from GE 7FA Units (pounds per hour)

Fuel	Range	Average	Std. Deviation
Natural Gas - Front-half (filterable)	0 – 17	4.8	
Natural Gas - Back-half (condensable)	0 - 15	14	
Natural Gas Total	1 - 29	7.5	
Fuel Oil - Front-half (filterable)	1 - 20	10	4
Fuel Oil Back-half (condensable)	3 - 21	14	6
Fuel Oil Total	4 - 37	24	9

Recent PM/PM_{10} emission limits are included in Table 12. Comparison is not simple because some of the limits represent filterable particulate matter while some of the limits represent the sum of filterable and condensable matter.

As previously discussed, there will be emissions of NO_X, SO_2 and SAM. These pollutants are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. The NO_X control technology of SCR can increase PM/PM_{10} emissions from the stack due to formation of ammonium sulfates prior to exiting.

Formation of ammonium species emitted from the stacks can be minimized by limiting the emissions of ammonia (known as slip). Elevated levels of ammonia slip may indicate a degrading catalyst. Almost all jurisdictions include a slip limit in conjunction with NO_X control technologies that rely on ammonia injection. A few permit limits are given in Table 12. Very low values ($\leq$ 0.2 ppmvd) were achieved at the ANP Blackstone project as described in Table 4.

It is noted that NH_3 emissions from the Stanton projected cited in Table 9 above ranged from 0.1 to 0.9 ppmvd @15% O_2 while firing natural gas. NH_3 and NO_X emissions while burning fuel oil were approximately 3 and 8 ppmvd respectively. Results from tests at KUA Unit 3 indicate that NH_3 emissions were 1.5 ppmvd @15% O_2 when firing fuel oil. The Department proposes an ammonia limit of 5 ppmvd @15% O_2.

Cooling Tower PM Emissions

The applicant's preliminary design includes a 22-cell mechanical draft cooling tower with the following specifications: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators with a drift rate of no more than 0.001 percent. Cooling towers may emit particulate matter based on the loading in the recirculating water.

FPL estimates annual emissions of 201 tons of PM due to drift losses assuming total dissolved solids (TDS) of 30,000 mg/L. PM_{10} emissions were projected to be 10 TPY based on TDS of 4,000 mg/L.

For reference, PM emissions estimated from the Martin Unit 8 project were estimated to be substantially less than from the Turkey Point project because the cooling water contains less TDS. It is possible for FPL to reduce the drift rate to further minimize PM emissions. For example, FPL Energy agreed to a drift rate limit of 0.0005% in conjunction with a TDS limit of 6,000 mg/L for the Tesla Project in Alameda County California.

The Department determines the draft BACT to be a design drift rate of no more than 0.0005% of the circulating water flow rate. At this level, maximum potential PM emissions from the cooling tower are expected to be on the order of 100 tons per year.

Applicant's PM/PM_{10} Proposal

FP&L proposes PM/PM_{10} BACT equal to 14.9 pounds per hour (lb/hr, front-half) when firing natural gas under all loads and modes of operation (DB, PK, PA). They propose a limit of 17.6 lb/hr (front-half) when firing fuel oil. They also propose an opacity limit of 10%. FPL proposes PM control from the cooling tower to be accomplished by a 0.001% drift rate design limitation.

Department's Draft PM/PM_{10} BACT Determinations

The following conditions are established as the draft BACT standards.

- The gas turbines shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 SCF of natural gas. The duct burners are limited to firing only natural gas meeting this specification. The gas turbines may fire distillate oil as a restricted alternate fuel (≤ 500 hours per year), which shall contain no more than 0.0015% sulfur by weight.
- Visible emissions shall not exceed 10% opacity based on a 6-minute average.
- Ammonia emissions (slip) shall not exceed 5 ppmvd.
- The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%.

4.6 Summary of Department Draft BACT Determination

Emissions from each gas turbine shall not exceed the values given in the following table.

Table 15. Draft BACT Determination – FPL Turkey Pt. Unit 5

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[g]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	37.8	
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	8.0, 24-hr
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO_X[b]	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	
		CT & DB	2.0	18.8	2.0, 24-hr
		CT & DB & (PA or PK)	NA	NA	
PM/PM_{10}[c]	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC[e]	Oil	CT	2.8	7.5	
	Gas	CT, normal	1.3	2.9	NA
		CT & DB	1.9	5.0	
Ammonia[f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

5 NEW SOURCE PERFORMANCE STANDARDS

5.1 Combustion Turbines

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart GG of 40 CFR 60. These requirements result in the following standards based on compressor inlet conditions of 59° F and 60% relative humidity:

- NO_X (gas) ≤ 110 ppmvd @ 15% O_2 (corrected for heat rate of 9250 Btu/KW-h at peak load) and;
- NO_X (oil) ≤ 103 ppmvd @ 15% O_2 (corrected for a heat rate of 9960 Btu/KW-h at peak load and 59° F); and
- SO_2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. An Appendix to the permit will summarize applicable federal requirements.

5.2 Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 495 MMBtu per hour (LHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NO_X ≤ 1.6 lb/MW-hr (gross)
- SO_2 ≤ 0.20 lb/MMBtu
- PM ≤ 0.03 lb/MMBtu

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.06 lb/MW-hr for NO_X. The specifications for the ultra low sulfur fuel oil and natural gas insure that the NSPS PM and SO_2 emission limits for the duct burners will easily be met. For example, if emissions from a duct burner alone exceeded its NSPS standards, then emissions from the duct burner and associated combustion turbine combined would exceed the BACT limits. An Appendix to the permit will summarize applicable federal requirements.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NSHAP Subpart YYYY, which became final on March 5, 2004.[27] According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[28] EPA has stayed the applicability of YYYY to units such as those proposed for the Turkey Point project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

Based on the same GE technical cited in the Section 4.3 above, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_X technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

The draft permit will reflect the present status of the rule. The final permit will reflect Subpart YYYY to the extent that it is applicable on the date the Department issues its final decision on the present application.

7. PERIODS OF EXCESS EMISSIONS

7.1 Excess Emissions Prohibited

In accordance with Rule 62-210.700(4), F.A.C., "Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited." All such preventable emissions shall be included in the compliance determinations for CO and NO_X emissions.

7.2 Alternate Standards and Excess Emissions Allowed

In accordance with Rule 62-210.700, F.A.C., "Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration." In addition, the rule states that, "Considering operational variations in types of industrial equipment operations affected by this rule, the Department may adjust maximum and minimum factors to provide reasonable and practical regulatory controls consistent with the public interest." Therefore, the Department has the authority to regulate defined periods of operation that may result in emissions in excess of the proposed BACT standards based on the given characteristics of the specific project.

Operation of the General Electric Frame 7FA gas turbine in lean premix mode is achieved by at least 50% of base load conditions. Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads (<10%), which results in higher emissions. In general, the sequences of startup/shutdown are managed by the automated control system.

Based on information from General Electric regarding startup and shutdown, the Department establishes the following conditions for excess emissions for each gas turbine/HRSG system.

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to three hours of excess emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting at least 24 hours.
- For cold startup to combined cycle operation, up to four hours of excess emissions are allowed. "Cold startup" is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

While NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation. The draft permit will also require the installation of a damper to reduce heat loss during combined cycle shutdowns to minimize the number of combined cycle cold startups.

Combined Cycle Operation with Dump Condenser: If the steam-electrical turbine generator was off line for some reason, it is possible that the gas turbine/HRSG systems would operate without producing any steam generated power. Instead, steam would be delivered to a dump condenser. Operation with a dump condenser must still meet the standards established for combined cycle operation with ammonia injection.

8. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

The following table shows the Department's estimated annual emissions from the completed combined cycle unit, including the cooling tower based on the draft permit conditions.

Pollutant	CO	Pb	NO_X	PM	PM_{10}	SO_2	SAM	VOC
Emissions (TPY)	464	0.026	312	320	224	193	19	68

The following ambient impact analyses were conducted using the higher values for PM and CO based on the applicant's original proposed BACT or subsequent revisions.

9. AIR QUALITY IMPACT ANALYSIS

9.1 Introduction

The proposed project will increase emissions of six pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2, VOC and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM and VOC. However, VOC is a precursor to a criteria pollutant, ozone; and any net increase of 100 tons per year of VOC requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

9.2 Major Stationary Sources in Miami-Dade County

The current largest stationary sources of air pollution in Miami-Dade County are listed below. The information is from annual operating reports submitted to the Department except as noted.

Table 16. Major Sources of SO_2 in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Pt. Plant (existing boilers)	9,135 (EPA)
Titan Industries	Tarmac Pennsucco Cement	~ 1,000 (est.)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	231
Florida Power &Light	***Turkey Pt. Plant (proposed project)***	***193***
Waste Management	Medley Landfill and Recycling	129
Miami-Dade County WASD	MDWASD/Central District WWTP	88

Table 17. Major Sources of NO_X in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Pt. Plant (existing boilers)	6,263 (EPA)
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	5,010
Titan Industries	Tarmac Pennsucco Cement	2,469
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	1,316
Homestead City Utilities	G.W. Ivey Power Plant	655
Florida Power & Light	Cutler Power Plant	547
Florida Power &Light	***Turkey Pt. Plant (proposed project)***	***312***

Table 18. Major Sources of CO in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Miami-Dade County SWD	Miami-Dade Resource Recovery Facility	3,106
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	995
Florida Power & Light	Turkey Pt. Power Plant (existing)	865
Florida Power &Light	***Turkey Point Plant (proposed project)***	***464***

Table 19. Major Sources of PM in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Florida Power & Light	Turkey Point Power Plant (existing)	734
Florida Power & Light	***Turkey Point Plant (proposed project)***	***419***
Titan Industries	Tarmac Pennsucco Cement	~ 325 (est.)
CSR Rinker Materials Corp.	Rinker Miami Cement Plant	157

Table 20. Major Sources of VOC in Miami-Dade County (2002)

Owner	Site Name	Tons per year
Nailite International	Nailite International	147
Fine Art Lamps	Fine Art Lamps	88
Waste Management	Medley Landfill and Recycling	80
Contender Boats Inc.	Contender Boats Site #1	78
DM Industries, Ltd.	DM Industries	76
GP Plastics Corp.	GP Plastics Corp. Miami Plant	76
Florida Power & Light	***Turkey Point Plant (proposed project)***	***68***
Florida Power & Light	Turkey Point Power Plant (existing)	64
Avanti Press, Inc.	Avanti Press, Inc.	64

Emissions from the proposed project are relatively low considering the high capacity (1,150 megawatts). For example the existing units emit 20 to 50 times as much SO_2 and NO_X despite their smaller capacity (total 880 MW).

For reference, an ongoing modernization project at Titan Industries, Tarmac Pennsucco Cement Plant will greatly reduce SO_2 emissions. A similar project at the CSR Rinker Miami Cement Plant already reduced SO_2 emissions by approximately 2,000 tons per year.

9.3 Pollutant Emissions in Miami-Dade County

Emission inventories have been prepared for each county in Florida for evaluation of regional haze. The following table is a listing of pollutant estimates from all kinds of sources in Miami-Dade County during 2002.[29] These include stationary sources, area sources, and on-road and non-road mobile sources. The category of area sources also includes fires.

Emissions from the proposed Turkey Point Unit 5 project are included. Emissions of ozone precursors (NO_X and VOC) from the proposed project will be minimal compared to total existing pollutant load. Thus the contribution to regional ozone formation will be very low.

Table 21. Pollutant Emissions in Miami-Dade County by Source Category (2002)

Source Category	SO_2	NO_X	CO	PM_{10}	VOC	NH_3
Stationary Sources	10,262	12,929	3,891	2,516	1,757	0
Area Sources	13,266	4,580	78,670	35,438	53,167	2,925
On-Road Mobile	1,989	46,158	492,121	1,230	49,007	1,940
Non-Road Mobile	1,976	19,062	197,091	24,946	15,646	11
Total	27,492	82,729	771,773	64,131	119,578	4,876
Turkey Pt. Unit 5	193	320	450	229	68	~200

The contributions to regional particulate matter emissions will also be very low even if all SO_2, NO_X, and NH_3 are ultimately converted to PM.

9.4 Air Quality and Monitoring in the Miami-Dade County

The Miami-Dade County Department of Environmental Resource Management (DERM) operates fifteen monitors at eleven sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, SO_2 and NO_2. The 2002 monitoring network is shown in the figure below.

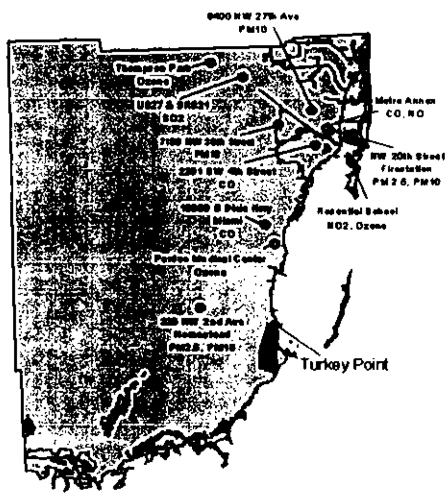

Figure 13. Miami-Dade DERM Ambient Air Monitoring Network

Measured ambient air quality information is summarized in the following table.

Table 22. Ambient Air Quality in Miami-Dade County Nearest to Project Site (2002)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Homestead	24-hour	38	31		150 [a]	ug/m^3
		Annual			19	50 [b]	ug/m^3
SO_2	US 27, SR 821	3-hour	5	5		500 [a]	ppb
		24-hour	4	4		100[a]	ppb
		Annual			2	20 [b]	ppb
NO_2	Rosenstiel, V. Key	Annual			6	53 [b]	ppb
CO	S. Dixie Highway	1-hour	3	3		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Perdue Medical	1-hour	0.091	0.086		0.12 [C]	ppm
		8-hour	0.070	0.064		0.08 [C]	ppm

a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

The data are reasonably representative of air quality near Turkey Point with the exception of SO_2. Since the existing Turkey Point fossil units constitute the largest source of SO_2, it is doubtful that the Station on US 27 and SR 821 adequately represents the Homestead area. However, measurements at sites throughout the state that are in the vicinity of larger SO_2 sources than the existing Turkey Point units are also in attainment with the respect to the SO_2 NAAQS. Therefore it is reasonable to conclude that SO_2 concentrations off of the Turkey Point site are also in attainment of the SO_2 NAAQS.

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels. The exception is ozone because it is formed from precursors that are clearly available (NO_X and VOC). The precursors are more available during drought years. The tendency to form ozone is accentuated by hot ambient temperature, high pressure, and relatively low wind speed.

9.5 Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I Everglades National Park (ENP) and the PSD Class II Areas (everywhere except the ENP).

If this modeling at worst-load conditions shows ground-level increases less than the SILs, the applicant is exempted from conducting any further modeling. If the modeled concentrations from the project exceed the SILs, then additional modeling including emissions from all facilities or projects (multi-source modeling) is required to determine the proposed project's impacts compared to the AAQS or PSD increments.

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except ENP). These values are tabulated in the table below and compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 23. Maximum Projected Air Quality Impacts from FP&L Turkey Point Unit 5 for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m³)	Significant Impact Level (ug/m³)	Baseline Concentrations (ug/m³)	Ambient Air Standards (ug/m³)	Significant Impact?
SO_2	Annual	0.1	1	~5	60	NO
	24-Hour	2	5	~10	260	NO
	3-Hour	8	25	~13	1300	NO
PM_{10}	Annual	0.2	1	~20	50	NO
	24-Hour	3.7	5	~40	150	NO
CO	8-Hour	30	500	~2300	10,000	NO
	1-Hour	73	2000	~3450	40,000	NO
NO_2	Annual	0.3	1	~11	100	NO

It is obvious that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Everglades National Park (ENP) located about 21 km to the west of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from annual SO_2, annual PM_{10}, and NO_2 are less than the applicable SILs for the Class I area. Therefore no further detailed modeling efforts are required for these pollutants.

Maximum predicted impacts from 24-Hour and 3-Hour SO_2, and 24-Hour PM_{10} are greater than the applicable SILs for the Class I area. Although the values are miniscule compared with the ambient air quality standards given in the previous table, additional modeling was required as discussed below.

Table 24. Maximum Air Quality Impacts from the FP&L Turkey Point Unit 5 Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.04	0.2	NO
	24-hour	0.5	0.3	YES
NO_2	Annual	0.073	0.1	NO
SO_2	Annual	0.04	0.1	NO
	24-hour	0.4	0.2	YES
	3-hour	1.8	1	YES

Preconstruction Ambient Monitoring Requirements

A preconstruction monitoring analysis is done for those pollutants with listed de minimis impact levels. These are levels, which, if exceeded, would require pre-construction ambient monitoring. For this analysis, as was done for the significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. As shown in the following table, the maximum predicted impacts for all pollutants with listed de minimis impact levels were less than these levels. Therefore, no pre-construction monitoring is required for those pollutants.

Table 25. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~40	NO
NO_2	Annual	0.3	14	~11	NO
SO_2	24-hour	2	13	~10	NO
CO	8-hour	30	575	~2300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential VOC emissions from the project to be 68 tons per year. Therefore, preconstruction monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project are the following:

- A multi-source AAQS and PSD increment analysis for 24-Hour and 3-Hour SO_2, and 24-Hour PM_{10} in the ENP Class I area;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. It incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition.

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. 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 satisfied 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 Miami International Airport. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification should EPA revise the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators. A more detailed discussion of the required analyses follows.

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP beyond 50 km from the proposed project. Meteorological MM4 and MM5 data used in this model was from 1990, 1992 and 1996. Meteorological surface data used were from Tampa, Daytona Beach, Vero Beach, Fort Myers, Key West, Miami, West Palm Beach and Orlando. Meteorological upper air data used were from Ruskin, Key West and West Palm Beach. Hourly precipitation data were obtained from 23 stations around the central and southern part of the state.

CALPUFF is a non-steady state, Lagrangian, long-range transport model that incorporates Gaussian puff dispersion algorithms. This model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, line, area, and volume sources.

The CALPUFF model has the capability to treat time-varying sources, is suitable for modeling domains from tens of meters to hundreds of kilometers, and has mechanisms to handle rough or complex terrain situations. Finally, the CALPUFF model is applicable for inert pollutants as well as pollutants that are subject to linear removal and chemical conversion mechanism.

Within 50 km of the source, the EPA-approved Industrial Source Complex Short-Term (ISCST3) dispersion model was used to evaluate the pollutant emissions from the proposed project. Characteristics, parameters and data used in this model are detailed above.

For Visibility within 50 km, the EPA-approved VISCREEN model was used. VISCREEN calculates the potential impact of a plume of specified emissions for specific transport and dispersion conditions. Surface meteorological data used in this model was obtained from the National Weather Service station in Miami from 1987 to 1991.

Multi-source PSD Class I Increment Analysis

The maximum predicted 3 and 24-hour SO_2 and 24-hour PM_{10} PSD Class I area impacts from this project and all other increment-consuming sources in the vicinity of the ENP are shown in the following table.

Table 26. PSD Class I Increment Analysis – ENP

Pollutant	Averaging Time	2nd-Highest-High Unit 5 Max Predicted Impact ($\mu g/m^3$)	2nd Highest-High All Sources Max Predicted Impact ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Impact Greater Than Allowable Increment?
SO_2	24-hour	0.4	4.1	5	NO
SO_2	3-hour	1.8	17.5	25	NO
PM_{10}	24-hour	0.5	2.1	5	NO

The existing Turkey Point Units have much greater ground level effects than predicted for the proposed project. This is obvious because emissions from the existing units are approximately 9,000 tons of SO_2 per year, whereas Unit 5 will emit less than 200 tons per year. However these effects are not included because the sources were in operation before the PSD Program and the baseline date for increment consumption.

It is possible to "expand" increment by reducing emissions from existing sources. Examples of SO_2 increment expansion projects are the Rinker Cement Plant modernization that reduced SO_2 emissions by approximately 2,000 tons per year and the on-going Tarmac Cement modernization that will result in a similar reduction.

9.6 Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Very low emissions are expected from the natural gas and distillate oil fired gas turbines in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be considerably less than the respective AAQS.

Since the project impacts are either less than significant or considerably less than the AAQS, it is reasonable to assume the impacts on soils, vegetation, or wildlife will be minimal or insignificant. The following example is instructive.

According to the applicant, lichens are a plant species in the area of the project that are sensitive to air pollutants. SO_2 levels of 200-400 $\mu g/m^3$ for a 6 hour period in the course of a week for 10 weeks can lead to adverse impacts. SO_2 impacts from the Turkey Point Expansion will be much less than these levels and therefore, will not contribute to adverse impacts on vegetation such as lichens.

Air pollutants can also adversely impact wildlife. According to the application, deer mice numbers will decline when exposed to levels of 13-157 $\mu g\ SO_2/m^3$ continuously for 5 months. Annual and 24-hour SO_2 levels predicted from the Turkey Point Expansion will be well below these levels and therefore, will not contribute to adverse impacts on wildlife, such as deer mice.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. The CALPUFF model is also used in this analysis to produce quantitative impacts. The results of the analysis show that nitrogen and sulfur deposition rates are slightly greater than the significant impact levels (0.01 kg/ha/yr) determined by the National Park Service.

According to the applicant, the predicted deposition rates of sulfur and nitrogen of 0.014 and 0.024 kg/ha/yr respectively, impacts are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

The low NO_X limit coupled with the use of ultra low sulfur fuel oil and inherently clean natural gas will minimize any possible effects due to sulfur and nitrogen deposition. Additionally the fuels are extremely low in mercury content. The very low sulfur deposition rate from the proposed project will also minimize activation of mercury in the soils by sulfur reducing bacteria.

Impact on Visibility and Regional Haze:

Consultation with the National Park Service Air Quality experts resulted in commitments by the applicant to use ultra low sulfur fuel oil that is not yet available in the Southeast Florida market. Additionally, that consultation also resulted in a commitment to lower NO_X emissions to 2 ppmvd @15% O_2.

The applicant submitted a regional haze analysis for the ENP. The analysis included modeling from the CALPUFF model and VISCREEN model.

Despite the measures proposed, through the application of BACT, to minimize SO_2, NO_X, and PM, the CALPUFF model predicts modeled impacts above the 5% visibility impairment based on criteria from the NPS. If the facility continuously operates on fuel oil, impairment can occur during 2 days in three years under atypical meteorological conditions for coastal Southeast Florida (temperature less than 35 degrees). Because of the limitation in fuel oil use, the probability that these two factors will coincide is low and the most probable expectation is that there will be no days of visibility impairment over a period of three years.

The coherent plume modeling with VISCREEN performed by the NPS showed no adverse impacts on the ENP.
The NPS also did an analysis to determine impacts at Biscayne National Park (a Class II area). The NPS determined that there may be plume impacts when firing oil if winds are from the south. This was determined with a 2.5 ppm NO_X limit for BACT. The 2.0 limit should slightly decrease these impacts. As stated above, fuel-oil firing will be limited to 500 hours per year, thus further reducing the probability of visibility impairment.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 250 additional workers will be needed over the 24-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the additional units will require few new permanent employees, which will cause no significant impact on the local area.

The project is a response to state-wide electrical growth and the legal requirement that certain investor owned utilities in Florida maintain a 20 percent electrical reserve. This project is one of several projects identified by FP&L in its annual 10 year plans submitted to the Public Service Commission.

Overall the project will not cause additional growth in the given area, but is a response to projected state-wide electrical power demand growth. Although the project could have been located elsewhere in Southeast Florida, the exact location is the result of economic optimization and transmission constraints.

Effects on Gas Supply and on Emissions from other Power Plants in Southeast Florida:

The existing FP&L Turkey Point Fossil Units 1 and 2 are basically residual oil fired units with natural gas co-firing capability. There are similar units at Port Everglades and Riviera Beach. Emissions, particularly of PM, SO_2, and SAM, are much greater for the residual fuel oil portion of the fuel used at the three plants than the natural gas portion.

Because the Turkey Point plant is "at the end of the pipeline," there is some concern regarding the gas supply and the possibility that natural gas usage by Turkey Point Unit 5 can decrease the availability of natural gas by the older units at Turkey Point, Port Everglades, and Riviera Beach.

According to the Annual Operating Reports received by the Department, the three plants used approximately 33 trillion BTUs of natural gas in 2002. The new Turkey Point Unit 5 will consume more than 60 trillion BTUs of natural gas.

For reference, in 1998, the natural gas transmission capacity to the state of Florida was approximately 1 billion standard cubic feet per day (bscfd). There have since been several expansions by Florida Gas Transmission Company. The Gulfstream Pipeline across the Gulf of Mexico was completed in 2002 and the estimated total transmission capacity to Florida is now closer to 3.5 bscfd.[30]

In response to a Department inquiry on gas availability to the three plants, FP&L responded that the Gulfstream Pipeline (cutting across the state) will supply all of the needs of the Martin Power Plant located further north. This will theoretically free up transportation capacity along the existing FGT network allowing for maintenance of present supplies and the additional future needs of Turkey Point Unit 5.

There are even more important developments that lend credence to the conclusion by FP&L that the Turkey Point project will not reduce gas availability for the existing units. At the present time, there are three proposed projects to construct liquefied natural gas (LNG) receiving and processing plants that will supply natural gas via pipelines to Southeast Florida. For example, on April 13, 2004 the Governor and Cabinet approved easements for two of the projects to cross state lands.[31, 32]

The two projects are the Tractebel Calypso and AES Ocean Express. These will enter South Florida at points in Broward County. The projects will supply natural gas (often associated with crude oil production) that is presently flared, reinjected, or left in place at distant sources in Africa, the middle east, Trinidad Tobago, etc.[33] Following is a diagram showing the expected path of one of the projects.

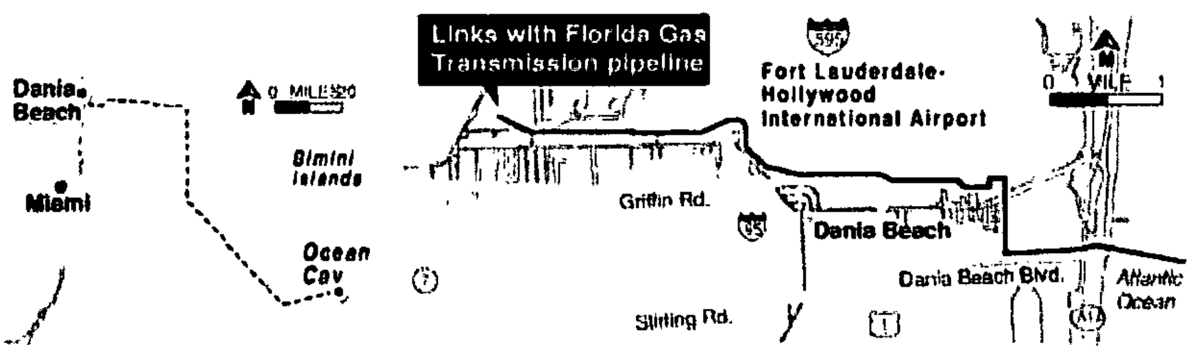

Figure 14. Projected Path of the AES Ocean Express Pipeline (Source: Sun-Sentinel)

El Paso and FPL recently announced agreements for participation of an FPL subsidiary (FPL Group Resources) in the third Bahamas LNG project and pipeline called Seafarer. El Paso and FPL Group Resources announced an agreement for 800 dekatherms per day of capacity on this project.[34, 35] This project will enter Florida in the area of Riviera Beach.

The total capacity of the three projects will be approximately 2.5 bscfd. The gas need at Turkey Point Unit 5 will be less than 0.2 bscfd. The supply from just one (let alone three) projects is sufficient to overwhelm the needs of the any foreseeable projects in Southeast Florida without impacting usage by the existing units.

In conclusion, the Department accepts that natural gas use at FP&L Turkey Point Unit 5 will not cause increased emissions from the existing residual fuel oil and gas co-fired-fired units in Southeast Florida.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, Residential growth in the area of the proposed project, Miami-Dade County, has increased 47% from 1977 to 2000. The number of vehicle miles traveled has also increased in the county, 58% from 1977 to 2001. During this time period, the number of those employed in the county grew about 71%.

The applicant addressed industrial growth in Miami-Dade County as well. The manufacturing industry has seen a 184% employee increase from 1977-2000 but the agricultural industry saw about a 19% drop in employees (1977-1999). Existing Utility Facilities in Miami-Dade County include the existing FPL Turkey Point Facility, FPL Cutler and the City of Homestead Utility. Currently, other than the expansion at Turkey Point, there are no permits for additional utility growth in the county.

Although, the population and miles traveled in Miami-Dade has increased since 1977, according to the application, air emissions from mobile sources have decreased. Carbon Monoxide has decreased by 61%, VOC has decreased by 65% and Nitrogen Oxides has decreased by 29%. Improvements to automobiles and fuels have more than counteracted any increase in mobile sources in Miami-Dade County.

Despite the growth in Southeast Florida, air quality has improved as evidenced by the redesignation of the Tri-County (Broward, Miami-Dade, and Palm Beach) area to attainment status with respect to the ozone standard.

Endangered Species Considerations

The purpose of the ESA is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[36] Under the law, species may be listed as either "endangered" or "threatened".

Endangered means a species is in danger of extinction throughout all or a significant portion of its range. Threatened means a species is likely to become endangered within the foreseeable future. All species of plants and animals, except pest insects, are eligible for listing as endangered or threatened.

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Chapter 2 of the Site Certification Application includes a characterization of the existing environment including vegetation, land use and ecology. Chapters 4 and 5 address the effects of construction and operation on ecological systems aquatic and terrestrial ecology. These sections are available at State and local environmental program offices.

According to the U. S. Fish and Wildlife Service (F&WS) website at there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004. The reader is referred to the following website: http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

For reference, the F&WS recently noticed the availability of an implementation schedule for the South Florida Multi-Species Recovery Plan designed to restore endangered or threatened animals and plants to the point where they are again secure, self sustaining components of their ecosystems.[37]

One endangered species of common interest is the American crocodile, the population of which numbers only about 1000 individuals. It lives within and near FP&L's property including the extensive cooling water canals visible in the following aerial photograph.

Figure 15. Cooling Canals at Turkey Pt. **Fig. 16. Crocodile - Everglades National Park**

According to FP&L's application, the precise project site is not part of the zone delineating the crocodile habitat, although parts of it can be used by the species. FP&L runs a crocodile management program and stated that it has increased the population of this species. FPL also stated in the application that any loss of potential habitat associated with the project will not jeopardize the continuing existence of the American crocodile or impact the designated habitat.

According to the application, other federally listed endangered species known to occur in Miami-Dade County including several kinds of turtles, the peregrine falcon, the Florida Panther, the manatee, and various plants such as spurges. There is also a State listing that is more extensive than the federal one.

Additional information is given in the separate Department Staff Report prepared in support of the preliminary Siting decision and available from the Department's Siting Office.

10. Preliminary Determination

The Department makes a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft determinations of Best Available Control Technology (BACT), review of the air quality impact analysis, and the conditions specified in the draft permit.

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the project engineer responsible for preparing the draft BACT determination and the permit as well as evaluating projecting the impacts on fuel supply. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

REFERENCES

1 Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station. September 2000.

2 Report. Spectrum Systems. Certification Testing, City of Tallahassee, Purdom Unit 8. September, 2000.

3 Paper. Cohn, A. and Scheibel, J., EPRI. Current Gas Turbine Developments and Future Projects. October 1997.

4 News Release. Calpine. Power Systems Mfg., LLC's Low Emissions Combustion System Achieves 5 ppm NO_X Commercial Certification at the Oyster Creek Power Plant in Freeport, Texas. May 5, 2003.

5 Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

6 News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

7 News Release. Catalytica. Catalytica Energy Systems XONON Cool Combustion System Demonstrating NO_X Emissions Well Below its 3 ppm Guarantee in Commercial Gas Turbine Applications. February 17, 2004.

8 Statement. EPA and Research Triangle Institute. ETV Joint Verification Statement. XONON™ Cool Combustion. December, 2000.

9 Letter. KenKnight, J., EPA Region 10 to Fiksdal, A., Washington Energy Facility Site Evaluation Council. BP Cherry Pt. Cogeneration Project. December 4, 2003.

10 Letters. Cusson, Thomas P., Massachusetts DEP to Maggiani, R., ANP Blackstone. Emissions Testing Results, ANP Blackstone Units 1 and 2.

11 White Paper. Emerachem. NO_X Abatement Technology for Stationary Gas Turbine Power Plants – An Overview of Selective Catalytic Reduction (SCR) and Catalytic Absorption ($SCONO_X$™) Emission Control Systems. September 19, 2002.

12 Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

13 Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.

14 White Paper. Rollins, W.S. et al. New Combined Cycle Technology for Achieving Ultra-Low Emissions. Coen Website. www.coen.com/i%5Fhtml/white%5Fnewcombcycle.html Accessed April 5, 2004.

15 Letter. Waters, G.D., Gulf Power to Halpin, M.P., FDEP. Lansing Unit Units 4 & 5 Test Results. May 6, 2001.

16 Fax Attachment. Kitchens, J. Alabama DEM to Reynolds, J., Florida DEP. Tables from Compliance Report – Alabama Power Company Barry Combined Cycle Units. Tests conducted Results of Testing, JEA Kennedy KCT 7. Tests conducted July 2000.

17 Report. Gulf Power. "Southern Company – Florida, LLC. State PSD Certification Emission Test Results." July 2003.

REFERENCES

[1] Report. Cubix Corporation. "Exhaust Emissions from a GE PG7241FA Simple Cycle Power Turbine at TECO Polk Power Station. September 2000.

[2] Report. Spectrum Systems. Certification Testing, City of Tallahassee, Purdom Unit 8. September, 2000.

[3] Paper. Cohn, A. and Scheibel, J., EPRI. Current Gas Turbine Developments and Future Projects. October 1997.

[4] News Release. Calpine. Power Systems Mfg., LLC's Low Emissions Combustion System Achieves 5 ppm NO_X Commercial Certification at the Oyster Creek Power Plant in Freeport, Texas. May 5, 2003.

[5] Compliance Manual. California EPA, CARB Compliance Division. Gas Turbines. June 1996.

[6] News Release. Catalytica. First Gas Turbine with Catalytica's XONON installed to Produce Electricity at a Utility. October 8, 1998.

[7] News Release. Catalytica. Catalytica Energy Systems XONON Cool Combustion System Demonstrating NO_X Emissions Well Below its 3 ppm Guarantee in Commercial Gas Turbine Applications. February 17, 2004.

[8] Statement. EPA and Research Triangle Institute. ETV Joint Verification Statement. XONON™ Cool Combustion. December, 2000.

[9] Letter. KenKnight, J., EPA Region 10 to Fiksdal, A., Washington Energy Facility Site Evaluation Council. BP Cherry Pt. Cogeneration Project. December 4, 2003.

[10] Letters. Cusson, Thomas P., Massachusetts DEP to Maggiani, R., ANP Blackstone. Emissions Testing Results, ANP Blackstone Units 1 and 2.

[11] White Paper. Emerachem. NO_X Abatement Technology for Stationary Gas Turbine Power Plants – An Overview of Selective Catalytic Reduction (SCR) and Catalytic Absorption ($SCONO_X$™) Emission Control Systems. September 19, 2002.

[12] Draft Report to the Legislature. California Air Resources Board. Gas -Fired Power Plant NO_X Emissions Controls and Related Environmental Impacts. March 2004.

[13] Technical Report GE 4213. Davis, L.B. and Black, S.H. GE Power Systems. "Support for Elimination of Oxidation Catalyst Requirements for GE PG7242FA DLN Combustion Turbines." August 2001.

[14] White Paper. Rollins, W.S. et al. New Combined Cycle Technology for Achieving Ultra-Low Emissions. Coen Website. www.coen.com/i%5Fhtml/white%5Fnewcombcycle.html Accessed April 5, 2004.

[15] Letter. Waters, G.D., Gulf Power to Halpin, M.P., FDEP. Lansing Unit Units 4 & 5 Test Results. May 6, 2001.

[16] Fax Attachment. Kitchens, J. Alabama DEM to Reynolds, J., Florida DEP. Tables from Compliance Report – Alabama Power Company Barry Combined Cycle Units. Tests conducted Results of Testing, JEA Kennedy KCT 7. Tests conducted July 2000.

[17] Report. Gulf Power. "Southern Company – Florida, LLC. State PSD Certification Emission Test Results." July 2003.

PERMITTEE:

Florida Power & Light
700 Universe Boulevard
Juno Beach, Florida 33408

Authorized Representative:
H. O. Nunez, Plant General Manager

FP&L Turkey Point Fossil Plant
DEP File No. 0250003-006-AC
Permit No. PSD-FL-338
SIC No. 4911
Expires: December 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of Unit 5 at the existing FP&L Turkey Point Fossil Plant, a "4-on-1" combined cycle unit with an electrical generating capacity of approximately 1150 MW. The project will includes four 170 MW gas turbine-electrical generator sets, four heat recovery steam generators, a single 470 MW steam turbine-electrical generator, and a mechanical draft cooling tower. The existing FP&L Turkey Point Fossil Plant is located east of Homestead and Florida City and next to Biscayne Bay in Miami-Dade County, Florida. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

STATEMENT OF BASIS

This PSD construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) The project was processed in accordance with the requirements of Rule 62-212.400, F.A.C., the preconstruction review program for the Prevention of Significant Deterioration (PSD) of Air Quality. Pursuant to Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S., the project is also subject to Electrical Power Plant Siting. The permittee is authorized to install the proposed equipment 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.

CONTENTS

Michael G. Cooke, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The existing Turkey Point Fossil Plant currently consists of two fossil fuel-fired steam electrical generating units and five "Black Start" diesel fired peaking generators. Fossil fuel-fired steam electric generating Units 1 and 2 (440 MW each) began operation in 1967 and 1968, respectively. The proposed "4 on 1" combined cycle Unit 5, which will consist of four gas turbines (170 MW each), four heat recovery steam generators, a single steam turbine-electrical generator (470 MW), and a mechanical draft cooling tower. New combined cycle Unit 5 will have a total generating capacity of approximately 1150 MW.

NEW AND MODIFIED EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units.

ID	Emission Unit Description
005	Unit 5A gas turbine (170 MW) with supplementary-fired heat recovery steam generator
006	Unit 5B gas turbine (170 MW) with supplementary-fired heat recovery steam generator
007	Unit 5C gas turbine (170 MW) with supplementary-fired heat recovery steam generator
008	Unit 5D gas turbine (170 MW) with supplementary-fired heat recovery steam generator
009	One distillate fuel oil storage tank for Unit 5 gas turbines
010	Mechanical draft cooling tower for Unit 5

Note: FPL Turkey Point Fossil Plant Unit 5 consists of four gas combustion turbine-electrical generator sets (Units 5A-5D), four supplementary gas-fired heat recovery steam generators (HRSGs), and a single steam turbine-electrical generator.

REGULATORY CLASSIFICATION

Title III: The existing facility is major for hazardous air pollutants (HAPs). This project is potentially subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines. (Note: See Appendix YYYY of this draft permit)

Title IV: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act.

Title V: Because potential emissions of at least one regulated pollutant exceed 100 tons per year, the existing facility is a Title V major source of air pollution in accordance with Chapter 62-213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and volatile organic compounds (VOC).

PSD: The project is located in an area designated as "attainment," "maintenance," or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is considered a "fossil fuel fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 PSD source categories with the lower PSD applicability threshold of 100 tons per year. Potential emissions of at least one regulated pollutant exceed 100 tons per year. Therefore, the facility is classified as a PSD-major source of air pollution with respect to Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) of Air Quality.

Siting: The project is subject to Electrical Power Plant Siting in accordance with Chapter 62-17, F.A.C. and Chapter 403, Part II, F.S.

PERMITTING AUTHORITY

All documents related to applications for permits to construct, operate or modify an emissions unit shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such documents shall also be submitted to the Compliance Authority.

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Miami-Dade County Department of Environmental Resources Management (DERM), Air Quality Management, 33 Southwest 2nd Avenue, Suite 900, Miami, Florida 33130-1540.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions
Appendix BD. Final BACT Determinations and Emissions Standards
Appendix CF. Citation Format and Definitions
Appendix Da. NSPS Subpart Da Requirements for Duct Burners
Appendix GC. General Conditions
Appendix GG. NSPS Subpart GG Requirements for Gas Turbines
Appendix SC. Standard Conditions
Appendix YYYY. NESHAP Subpart YYYY Requirements for Gas Turbines
Appendix XS. Semiannual NSPS Excess Emissions Report

RELEVANT DOCUMENTS

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action and are on file with the Department.

- Permit application received on November 14, 2003;
- Department PSD Application Sufficiency comments dated January 2, 2004;
- Environmental Protection Agency Region 4 letter dated January 15, 2004;
- Department of Interior/NPS letter dated February 27, 2004;
- Sufficiency Responses received March 1, 2004;
- Draft permit package issued on May 28, 2004;
- Comments received regarding draft permit;
- Draft permit revised due to comments; and
- Final order issued by the Siting Board.

1. General Conditions: The permittee shall operate under the attached General Conditions listed in Appendix GC of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

2. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and the Title 40, Parts 51, 52, 60, 72, 73, and 75 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. 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. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

3. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit. [Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

4. New or Additional Conditions: 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.]

5. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit shall be obtained prior to beginning construction or modification. [Chapters 62-210 and 62-212, F.A.C.]

6. Application for Title IV Permit: At least 24 months before the date on which the new unit begins serving an electrical generator greater than 25 MW, the permittee shall submit an application for a Title IV Acid Rain Permit to the Department's Bureau of Air Regulation in Tallahassee and a copy to the Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia. [40 CFR 72]

7. Title V Permit Revision: The permittee shall submit an application for a revised Title V air operation permit at least 90 days before the expiration of this permit, but no later than 180 days after commencing operation of the new units. To apply for a revised Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, a Compliance Assurance Monitoring Plan (as necessary), and such additional information as the Department may by law require.

A. UNIT 5 COMBINED CYCLE GAS TURBINE (EUs 005, 006, 007, AND 008)

This section of the permit addresses the following emissions units.

Emissions Units 005, 006, 007, 008

Description: Emissions units 005, 006, 007, and 008 each consist of a General Electric Model PG7241(FA) gas turbine-electrical generator set, an automated gas turbine control system, an inlet air filtration system, an evaporative inlet air-cooling system, a gas-fired heat recovery steam generator (HRSG), a HRSG stack, and associated support equipment. In addition, the project also includes a single steam turbine-electrical generator that serves all four gas turbine/HRSG systems.

Fuels: Each gas turbine fires natural gas as the primary fuel and distillate fuel oil as a restricted alternate fuel.

Generating Capacity: Each of the four gas turbine-electrical generator sets has a nominal generating capacity of 170 MW for gas firing (180 MW for oil firing). Exhaust from each gas turbine passes through a separate supplementary-fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to the single steam turbine-electrical generator, which has a generating capacity of 470 MW. The total generating capacity of the "4 on 1" combined cycle unit is approximately 1150 MW.

Controls: The efficient combustion of natural gas and restricted firing of ultra low sulfur distillate fuel oil minimizes the emissions of CO, PM/PM_{10}, SAM, SO_2 and VOC. Dry Low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system further reduces NO_X emissions.

Stack Parameters: Each HRSG has a stack at least 130 feet tall with a nominal diameter of 19 feet. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following summarizes the exhaust characteristics:

Fuel	Heat Input Rate (LHV)	Compressor Inlet Temp.	Exhaust Temp., °F	Flow Rate ACFM
Gas	1,608 MMBtu/hour	59° F	202° F	1,023,872
Oil	1,830 MMBtu/hour	59° F	295° F	1,224,407

Continuous Monitors: Each stack is equipped with continuous emissions monitoring systems (CEMS) to measure and record CO and NO_X emissions as well as flue gas oxygen or carbon dioxide content.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of the Best Available Control Technology (BACT) were made for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2) and volatile organic compounds (VOC). See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]
2. NSPS Requirements: The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60. For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit. [Rule 62-204.800(7), F.A.C.]

EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system and an evaporative inlet air-cooling system. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to 290 °F before combustion to increase overall unit efficiency. This will be accomplished by feedwater heat exchangers. [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *Selective Catalytic Reduction (SCR) System*: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from each gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

   d. *Ammonia Storage*: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.

   [Design; Rule 62-212.400(BACT), F.A.C.]

5. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (5A-5D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. *{Permitting Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 470 MW.}* [Application; Design]

PERFORMANCE RESTRICTIONS

6. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,608 MMBtu per hour when firing natural gas and 1,830 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods

of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

7. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

8. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbines may operate under the following methods of operation.

   a. *Hours of Operation*: Subject to the operational restrictions of this permit, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. Each gas turbine shall fire no more than 500 hours of fuel oil during any consecutive 12 months.

   c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   d. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging."

   e. *Duct Firing*: When firing natural gas, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

   f. *High Power Modes (Peaking and Power Augmentation)*: When firing natural gas and only while practicing duct firing, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. When firing natural gas and only while practicing duct firing, steam may be injected into each gas turbine expansion section to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation," the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total hours of power augmentation plus the total hours of peaking shall not exceed 400 hours per gas turbine during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[g]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.0, 24-hr
NO_X[b]	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM_{10}[c]	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC[e]	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia[f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The sulfur fuel specifications established in Condition No. 8 of this section combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard and Section 24.41.1 of the Miami-Dade County Code shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section. Compliance with the SO_2 BACT also insures compliance with Section 24.41.3 of the Miami-Dade County Code.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Each SCR system shall be designed and operated for ammonia slip limit of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59°F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

{Permitting Notes: "DB" means duct burning. "PA" means power augmentation. "PK" means peaking, "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

[Rule 62-212.400(BACT), F.A.C.]

10. Combined Cycle Operation With Steam Dumped to Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. This is not considered a separate mode of operation with respect to emission limits. When operating in this manner, each unit shall comply with the respective standards given in Condition 9 for each mode of operation indicated therein. [Application]

11. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. *{Permitting Note: The BACT limits applicable during duct firing are much more stringent than the standards of NSPS Subpart Da for duct burners. Therefore compliance with the BACT limits insures compliance with the emission limitations in Subpart Da}.* [Subpart Da, 40 CFR 60]

EXCESS EMISSIONS

12. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, oil-to-gas fuel switches and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

    a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Permitting Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

    b. For shutdown of the combined cycle operation, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

    c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

    d. For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.

    Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

16. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

17. Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

18. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Stack test data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NO_X standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. CO and NO_X emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

19. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 9 above. [Rule 62-212.400 (BACT), F.A.C.]

20. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period.

{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions. The Department retains the right to require VOC testing if CO limits are exceeded or for the reasons given in Appendix SC, Condition 17, Special Compliance Tests.}

[Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

21. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
    b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.
    d. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. *{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}* [Rule 62-212.400(BACT), F.A.C.]

f. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 16 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

g. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[NSPS Subparts Da and GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR Part 51, Appendix P; 40 CFR 60, Appendix B - Performance Specifications; 40 CFR 60, Appendix F - Quality Assurance Procedures; and Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

22. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

RECORDS AND REPORTS

23. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

24. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

25. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the following records of the sulfur contents.

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

    b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

    The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

26. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_X emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of

startup, shutdown, or malfunction; and SO_2 emissions in excess of the NSPS standards except during startup or shutdown. An example of the report is provided on Appendix XS. [40 CFR 60.7]

28. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the permit standards. Such information shall also be summarized for startups, shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

B. DISTILLATE FUEL OIL STORAGE TANK (EU 009)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
009	One distillate fuel oil storage tank for Unit 5 gas turbines (approximately 4.2 million gallons)

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the record keeping requirements specified below. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.; and Section 24.41.6, Miami-Dade County Code.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 4.3 million gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 5 gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The hours of operation are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

NOTIFICATION, REPORTING AND RECORDS

4. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-204.800(7)(b)16, F.A.C.; 40 CFR 60.116b(a) and (b)]

C. COOLING TOWER (EU 010)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
010	22-cell mechanical draft cooling tower

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one new 22-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 306,000 gpm; design hot/cold water temperatures of 105° F/87° F; a design air flow rate of 1,500,000 per cell; a liquid-to-gas air flow ratio of 1.045; and drift eliminators. The permittee shall submit the final design details within 60 days of selecting the vendor. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall submit certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. *{Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 100 tons of PM per year and less than 5 tons of PM_{10} per year. Actual emissions are expected be lower than these rates.}*. [Rule 62-212.400(BACT), F.A.C.]

CONTENTS

NSPS Subpart A, Identification of General Provisions

Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

Refer to the draft BACT document issued with initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [g]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO_X [b]	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM_{10} [c]	Oil/Gas	All Modes	Fuel Specifications		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC [e]	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia [f]	Oil/Gas	CT, All Modes	5	NA	NA

a. Continuous compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode. Compliance with the 24-hour CO CEMS standards shall be determined separately for the Duct Burner/Power Augmentation mode and all other modes based on the hours of operation for each mode.

b. Continuous compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO_2.

c. The sulfur fuel specifications combined with the efficient combustion design and operation of each gas turbine represents (BACT) for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications effectively limit the potential emissions of SAM and SO_2 from the gas turbines and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

g. The mass emission rate standards are based on a turbine inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E., Program Administrator
New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

Trina L. Vielhauer, Chief
Bureau of Air Regulation

Date

Approved By:

Michael G. Cooke, Director
Division of Air Resources Management

Date

CITATION FORMAT AND DEFINITIONS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AF, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AF" identifies the permit as a minor federally enforceable state operation permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CFR 60.7]

Means: Title 40, Part 60, Section 7

DEFINITIONS [RULE 62-210.200, F.A.C.]

(119) Excess Emissions - Emissions of pollutants in excess of those allowed by any applicable air pollution rule of the Department, or by a permit issued pursuant to any such rule or Chapter 62-4, F.A.C. The term applies only to conditions which occur during startup, shutdown, soot blowing, load changing or malfunction.

(179) Malfunction - Any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.

(258) Shutdown - The cessation of the operation of an emissions unit for any purpose.

(275) Startup - The commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 5 gas turbine/HRSG systems, which are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.40a Applicability and Designation of Affected Facility.

The HRSG duct burner systems are part of an electric utility steam generating unit that is capable of combusting more than 250 MMBtu per hour heat input of fossil fuel for which construction or modification is commenced after September 18, 1978. Therefore, the requirements of NSPS Subpart Da apply to the HRSG duct burners systems. Only emissions resulting from combustion of fuels in the steam generating unit are subject to this subpart. Emissions from the gas turbines are subject to the requirements of NSPS Subpart GG. The HRSG duct burner systems are also subject to the applicable requirements of the General Provisions in Subpart A.

§ 60.41a Definitions.

"Duct burner" means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

"Electric utility combined cycle gas turbine" means any combined cycle gas turbine used for electric generation that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam distribution system that is constructed for the purpose of providing steam to a steam electric generator that would produce electrical power for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility.

"Fossil fuel" means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such material for the purpose of creating useful heat.

"Gross output" means the gross useful work performed by the steam generated. For units generating only electricity, the gross useful work performed is the gross electrical output from the turbine/generator set. For cogeneration units, the gross useful work performed is the gross electrical output plus one half the useful thermal output (i.e., steam delivered to an industrial process).

"Potential electrical output capacity" is defined as 33 percent of the maximum design heat input capacity of the steam generating unit (e.g., a steam generating unit with a 100–MW (340 million Btu/hr) fossil-fuel heat input capacity would have a 33–MW potential electrical output capacity). For electric utility combined cycle gas turbines the potential electrical output capacity is determined on the basis of the fossil-fuel firing capacity of the steam generator exclusive of the heat input and electrical power contribution by the gas turbine.

"Steam generating unit" means any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam (including fossil-fuel-fired steam generators associated with combined cycle gas turbines; nuclear steam generators are not included).

§ 60.42a Standard for Particulate Matter.

§ 60.42a(a)(1) establishes a particulate matter limit of 0.03 lb/MMBtu heat input from the combustion of gaseous fuel and an opacity limit of 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum PM/PM_{10} emissions are expected to be less than 0.01 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. The stack opacity is limited by permit to 10% or less. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

§ 60.43a Standard for Sulfur Dioxide.

In accordance with § 60.43a(b)(2), sulfur dioxide emissions shall not exceed 0.20 lb/MMBtu heat input from the combustion of gaseous fuel for uncontrolled sources. Natural gas is the primary fuel for the gas turbines with very low sulfur distillate oil ($\leq$ 0.05% sulfur by weight) as a backup fuel. Natural gas is the exclusive fuel for the duct burner systems. As the worst case, the maximum SO_2 emissions are expected to be less than 0.05 lb/MMBtu heat input from firing distillate oil in the gas turbine and natural gas in the duct burners. Therefore, the Department determines that compliance with the conditions of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

§ 60.44a Standard for Nitrogen Oxides.

In accordance with § 60.44a(d)(1), nitrogen oxides (expressed as NO_2) from a gas turbine/HRSG system with duct burners shall not exceed 1.6 pounds per megawatt-hour gross energy output. The permittee shall demonstrate compliance with this requirement based upon an initial test. Thereafter, compliance with the BACT standards of the PSD permit will demonstrate compliance with the NSPS Subpart Da limit. After investigation, if there is good reason to believe that this standard is being violated, the Department may require subsequent compliance testing in accordance with Rule 62-297.310(7)(b), F.A.C.

§ 60.46a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart. Therefore, no testing is required to demonstrate compliance with the standards specified in § 60.42a (particulate matter) and § 60.43a (sulfur dioxide). Compliance with the opacity limit of 10% established in the PSD permit ensures compliance with the NSPS opacity standard.

In accordance with § 60.46a(k)(1), compliance with the nitrogen oxides (NO_X) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

E = [(Csg ×Qsg) - (Cte ×Qte)]/(Osg ×h) (Equation 1)

Where:

E = Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output

Csg = Average hourly concentration of NO_X exiting the steam generating unit, ng/ dscm (lb/dscf)

Cte = Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)

Qsg = Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)

Qte = Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)

Osg = Average hourly gross energy output from steam generating unit, J (Mwh)

h = Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

Method 7E of Appendix A of Part 60 shall be used to determine the NO_X concentrations (Csg and Cte). Method 2, 2F or 2G of Appendix A of Part 60, as appropriate, shall be used to determine the volumetric flow rates (Qsg and Qte) of the exhaust gases. The volumetric flow rate measurements shall be taken at the same time as the concentration measurements.

The owner or operator shall develop, demonstrate, and provide information satisfactory to the Administrator to determine the average hourly gross energy output from the steam generating unit, and the average hourly percentage of the total heat input to the steam generating unit derived from the combustion of fuel in the affected duct burner.

Compliance with the emissions limits under § 60.44a(d)(1) is determined by the three-run average (nominal 1- hour runs) for the initial performance tests. Thereafter, compliance with the NOx limits established in the PSD permit shall demonstrate compliance with NO_X limit specified in NSPS Subpart Da.

In accordance with § 60.46a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

Determine compliance with the applicable NO_X emissions limits by measuring the emissions combined with the emissions from the other units utilizing the common steam turbine; or

Develop, demonstrate, and provide information satisfactory to the Administrator on methods for apportioning the combined gross energy output from the steam turbine for each of the affected duct burners. The Administrator may approve such demonstrated substitute methods for apportioning the combined gross energy output measured at the steam turbine whenever the demonstration ensures accurate estimation of emissions regulated under Part 60.

§ 60.47a Emission Monitoring.

In accordance with § 60.47a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_X standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.48a Compliance Determination Procedures and Methods.

In accordance with § 60.48a (d)(1), EPA Method 19 shall be used to determine the NO_X emission rate when demonstrating compliance with the NO_X standard specified in § 60.44a. In accordance with § 60.48a(f), electric utility combined cycle gas turbines are performance tested for particulate matter, sulfur dioxide, and nitrogen oxides using the procedures of Method 19. The sulfur dioxide and nitrogen oxides emission rates from the gas turbine used in Method 19 calculations are determined when the gas turbine is performance tested under subpart GG. The potential uncontrolled particulate matter emission rate from a gas turbine is defined as 17 ng/J (0.04 lb/million Btu) heat input.

§ 60.49a Reporting requirements.

Compliance with reporting requirements of the PSD permit ensure compliance with the requirements of NSPS Subpart Da.

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

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.

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, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

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.

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.

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.

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.

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.

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.

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 extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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.

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.

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emssion Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

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.

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.

SECTION IV. APPENDIX GG

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

The Unit 5 gas turbines are regulated as Emissions Units 005, 006, 007, and 008.

§ 60.330 Applicability and Designation of Affected Facility.

Each Unit 5 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

(a) Stationary gas turbine means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) Simple cycle gas turbine means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(d) Combined cycle gas turbine means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(g) ISO standard day conditions mean 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) Efficiency means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) Peak load means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) Base load means the load level at which a gas turbine is normally operated.

(q) Electric utility stationary gas turbine means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

§ 60.332 Standard for Nitrogen Oxides.

In accordance with § 60.332(a)(1) and (b), emissions of nitrogen oxides (NO_X) from electric utility stationary gas turbines with a heat input at peak load greater than 100 MMBtu Btu per hour (LHV) shall not exceed the following standard.

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

Where:

STD = Allowable NO_X emissions (percent by volume at 15 percent oxygen and on a dry basis).

Y = Manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_X emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(3) of this section.

§ 60.332(a)(3) defines an allowable NO_X contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9250 Btu/KW-h at peak load and for oil firing is 9960 Btu/KW-h at peak load. This results in "Y" values of 9.8 for gas firing and 10.5 for oil firing. The equivalent NSPS NO_X emission standards are 110/103 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NOx standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil (≤ 0.05% sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

The PSD permit requires keeping monthly records of the fuel sulfur content of natural gas. For distillate oil, the PSD permit requires initial fuel sulfur sampling and then keeping records of the fuel sulfur content based on vendor information "as supplied" for each subsequent shipment. Appropriate test methods are also specified in the PSD permit. These requirements constitute a custom fuel monitoring schedule that ensures compliance with the NSPS requirements for monitoring the nitrogen and sulfur contents of the fuels. The requirement to monitor the nitrogen contents of these fuels is waived due to negligible concentrations and the PSD conditions that require compliance with the NO_X standards to be demonstrated by CEMS. The CEMS shall be installed, operated, and maintained in accordance with the requirements of the PSD permit.

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any 1-hour period of NO_X emissions greater than the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

In accordance with § 60.335(c), compliance with the nitrogen oxides standards in § 60.332 shall be determined by computing the nitrogen oxides emission rate (NO_X) for each run using the following equation:

$$NOx = (NOxo)\,(Pr/Po)^{0.5}\,e^{19(Ho-0.00633)}\,(288°K/Ta)^{1.53}$$

Where:

NOx	=	Emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent
NOxo	=	Observed NOx concentration, ppm by volume
Pr	=	Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
Po	=	Observed combustor inlet absolute pressure at test, mm Hg
Ho	=	Observed humidity of ambient air, g H_2O/g air
e	=	Transcendental constant, 2.718
Ta	=	Ambient temperature, °K

Tests for nitrogen oxides emissions shall be conducted in accordance with the schedule and methods specified in the PSD permit. The permittee is allowed to conduct initial performance tests at a single load because a NO_X monitor shall be used to demonstrate compliance with the specified NO_X limits. The permittee is allowed to make the initial compliance demonstration for NO_X emissions using certified CEMS data, provided that compliance is based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NO_X monitor. The permittee is not required to have the NO_X monitor continuously correct NO_X emissions concentrations to ISO conditions. However, the permittee shall make the correction when required by the Department or Administrator.

The permittee shall use the methods specified in the PSD permit to demonstrate compliance with the fuel sulfur specification, which will ensure compliance with the NSPS standard.

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

1. 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 permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; 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 or the regulations. [Rule 62-4.130, F.A.C.]

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

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

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

TESTING REQUIREMENTS

10. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate 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 purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

12. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.
    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

    [Rule 62-297.310(4), F.A.C.]

14. Determination of Process Variables
    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight 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.]

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide

sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.
2) The facility at which the emissions unit is located.
3) The owner or operator of the emissions unit.
4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8) The date, starting time and duration of each sampling run.
9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10) The number of points sampled and configuration and location of the sampling plane.
11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12) The type, manufacturer and configuration of the sampling equipment used.
13) Data related to the required calibration of the test equipment.
14) Data on the identification, processing and weights of all filters used.
15) Data on the types and amounts of any chemical solutions used.
16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18) All measured and calculated data required to be determined by each applicable test procedure for each run.
19) The detailed calculations for one run that relate the collected data to the calculated emission rate.
20) The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From ____________________ to ____________________

Company: ______________________________

Emission Limitation: ______________________________

Address: ______________________________

Monitor Manufacturer: ______________________________

Model No.: ______________________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ______________________________

Total source operating time in reporting period [1]: ____________________

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown .... ____	a. Monitor equipment malfunctions .... ____
b. Control equipment problems .... ____	b. Non-Monitor equipment malfunctions .... ____
c. Process problems .... ____	c. Quality assurance calibration .... ____
d. Other known causes .... ____	d. Other known causes .... ____
e. Unknown causes .... ____	e. Unknown causes .... ____
2. Total duration of excess emissions .... ____	2. Total CMS Downtime .... ____
3. Total duration of excess emissions x (100) / [Total source operating time] .... %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] .... %[2]

1 For opacity, record all times in minutes. For gases, record all times in hours.

2 For the reporting period: If the total duration of excess emissions is 1 percent or greater of the total operating time or the total CMS downtime is 5 percent or greater of the total operating time, both the summary report form and the excess emission report described in 40 CFR 60.7(c) shall be submitted.

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: ______________________________

Signature: ______________________________ *Date*: ____________________

Title: ______________________________

NESHAP REQUIREMENTS FOR GAS TURBINES

The Turkey Point plant is an existing major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines would be subject to NSHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit would be considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY. EPA has stayed the applicability of YYYY to units such as those proposed for the Turkey Point project and EPA proposed to permanently delete such units (as well as certain other classes) from the list of sources subject to the regulation.

According to General Electric, the GE 7FA gas turbine achieves less than 25 ppbvd at 15% oxygen. FP&L proposes to meet the limit proposed in YYYY of 91 ppmvd.

The very low VOC and CO emissions characteristics of the GE 7FA combustion turbines as well as the Dry Low NO_X technology employed by these units insure that formaldehyde emissions will be at the lowest end of the spectrum.

Any applicable provisions will be included in this section at the time that the Department takes final action on the PSD permit application.

P.E. CERTIFICATION STATEMENT

PERMITTEE

Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

FP&L Turkey Point Fossil Plant DEP File No. 0250003-006-AC Permit No. PSD-FL-338

PROJECT DESCRIPTION

The applicant proposes to construct a "4-on-1" 1150 MW combined cycle Unit 8 consisting of the following equipment and specifications: four 170 MW gas turbine-electrical generator sets; four supplementary gas-fired heat recovery steam generators (495 MMBtu/hour, LHV); a common steam-electrical generator (470 MW); a mechanical draft cooling tower; and other associated support equipment. Each gas turbine will fire natural gas as the primary fuel and ultra low sulfur distillate oil as a restricted alternate fuel ($\leq$ 500 hours/year). Additional equipment includes four 131-foot stacks, an aqueous ammonia storage tank, and a distillate fuel oil storage tank.

CO, PM/PM_{10}, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and SO_2 will be minimized by firing natural gas and use of ultra low sulfur (<0.0015% sulfur) distillate fuel oil. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions. These controls are determined to represent the Best Available Control Technology (BACT). The following limited alternate methods of operation are allowed: duct burning (DB, 2880 hours per year); power augmentation or peaking ($\leq$ 400 hours/year). The draft permit includes the following standards for emissions of CO, NO_X, VOC, and ammonia.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr	ppmvd @ 15% O_2
CO	Oil	Combustion Turbine (CT)	8.0	37.8	8.0, 24-hr
	Gas	CT, Normal	4.1	16.3	
		CT & Duct Burner (DB)	7.6	38.3	
		CT & DB & PK	NA	NA	
		CT & DB & PA	NA	NA	14.1, 24-hr
NO_X	Oil	CT	8.0	62.1	8.0, 24-hr
	Gas	CT, Normal	2.0	13.0	2.0, 24-hr
		CT & DB	2.0	18.8	
		CT & DB & (PA or PK)	NA	NA	
PM/PM_{10}	Oil/Gas	All Modes	Fuel Specifications Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
VOC	Oil	CT	2.8	7.5	NA
	Gas	CT, normal	1.3	2.9	
		CT & DB	1.9	5.0	
Ammonia	Oil/Gas	CT, All Modes	5	NA	NA

***I HEREBY CERTIFY** that the air pollution control 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).*

5/28/04

Alvaro A. Linero, P.E. (Date)
Registration Number: 26032

Florida Department of Environmental Protection
Division of Air Resources Management, Bureau of Air Regulation
2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400

Memorandum

Florida Department of
Environmental Protection

TO: Trina L. Vielhauer

FROM: A.A. Linero A.A. Linero 5/25

DATE: May 25, 2004

SUBJECT: FPL Turkey Point 1,150 MW Expansion Project
DEP File No. 025003-006-AC (PSD-FL-338)

Attached is the draft permit package for FPL Turkey Point Power Plant Unit 5. The project consists of a "four on one" gas-fired combined cycle base load unit with a total capacity of 1,150 megawatts. The site is located near the Class I Everglades National Park and is adjacent to the Class II Biscayne National Park.

Each Heat Recovery Steam Generator will be equipped with a large duct burner for supplemental firing to boost steam production.

Nitrogen Oxides (NO_X) emissions will be controlled by SCR to 2.0 parts per million at 15 percent oxygen (ppmvd @15%O_2) on a 24-hr basis when firing natural gas. This is the lowest value yet in the Southeast. Emissions when firing fuel oil will be 8 ppmvd@15% O_2.

Carbon monoxide (CO) will be controlled to 4.1 and 8.0 ppmvd @15% O_2 when burning natural gas and fuel oil respectively. These are the lowest values yet for projects without the use of oxidation catalyst. Working with FP&L we were able to get GE to guarantee these limits for the first time that I am aware of. There are allowances for the duct burners when used, and power augmentation (steam injection) and peaking.

VOC, SO_2, sulfuric acid mist and particulate matter emissions will be inherently low due to the use of inherently clean fuels. FP&L has committed to use ultra low sulfur (0.0015% S) fuel oil for backup purposes 500 hours per year per unit.

We have set an ammonia limit of 5 ppmvd @15% O_2. This not only minimizes particulate formation, but also reduces nitrogen deposition in the Everglades NPS.

There has been considerable consultation over the past year with the NPS. They submitted comments on the application. Their comments and concerns influenced the draft NO_X BACT determination as well as the use of ultra low sulfur fuel oil. We expect further comments between now and when the Site Certification Hearing is held.

We concluded that the project will not cause or contribute to violations of the ambient air quality standards or the Class I increments. I am also comfortable that there will be no adverse impacts on air quality related values (AQRVs) such as visibility. However, we will need to assess any future opinions submitted by the NPS as conclusions regarding AQRVs fall within their purview.

I recommend your approval of the attached package for public distribution.

AAL/aal

Attachments