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:

Ben Jacoby, Attorney-In-Fact
Fort Pierce Re-Powering
Project, LLC
1400 Smith Street
Houston, TX 77002-7361

X N. Wood

☐ 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)
7000 0600 0026 4129 8498

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)

7000 0600 0026 4129 8498

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

Postmark Here

Recipient's Name (Please Print Clearly) (to be completed by mailer)
Ben Jacoby
Street, Apt. No.; or PO Box No.
1400 Smith Street
City, State, ZIP+4
Houston, TX 77002-7361

PS Form 3800, February 2000 See Reverse for Instructions

CF Per the initial application, CO was PSD. The BACT would make them Non-PSD for CO, However Jeff + Enron are just as happy to keep CO as PSD + BACT. CO is controlled with catalyst.

Department of Environmental Protection

FLORIDA

Jeb Bush
Governor

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

David B. Struhs
Secretary

June 18, 2001

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Ben Jacoby, Attorney-In-Fact
Fort Pierce Re-Powering Project, LLC
1400 Smith Street
Houston, TX 77002-7361

Re: Project No. 1110102-001-AC
Air Permit No. PSD-FL-320
New 180 MW Combined Cycle Gas Turbine Project

Dear Mr. Jacoby:

Enclosed is one copy of the Draft Permit to construct a new 180 MW combined cycle gas turbine plant adjacent to the existing H.D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. The Department's "Technical Evaluation and Preliminary Determination", "Intent to Issue Permit", and the "Public Notice of Intent to Issue Permit" are also included.

The "Public Notice of Intent to Issue Permit" must be published one time only, as soon as possible, in the legal advertisement section of a newspaper of general circulation in the area affected, pursuant to the requirements 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 days of publication. Failure to publish the notice and provide proof of publication may result in the denial of the permit.

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any other questions, please contact Jeff Koerner at 850/921-9536.

Sincerely,

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

CHF/AAL/jfk

Enclosures

In the Matter of an
Application for Air Permit by:

Fort Pierce Re-Powering Project, LLC
1400 Smith Street
Houston, TX 77002-7361

Authorized Representative:
Ben Jacoby, Attorney-In-Fact

Fort Pierce Re-Powering Project, LLC
Project No. 1110102-001-AC
Air Permit No. PSD-FL-320
Emission Unit 001
St. Lucie County, Florida

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit (copy of Draft Permit attached) for the proposed project as detailed in the application and the enclosed Technical Evaluation and Preliminary Determination, for the reasons stated below. The applicant, Fort Pierce Re-Powering Project, LLC, applied on April 19, 2001 to the Department for an air construction permit to construct a new 180 MW combined cycle gas turbine plant adjacent to the existing H.D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. The Draft Permit authorizes the construction of one Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set (180 MW), a gas-fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air-cooling, and other associated equipment.

The Department has permitting jurisdiction under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-210, and 62-212 of the Florida Administrative Code (F.A.C.). The above actions are not exempt from permitting procedures. The Department has determined that an air construction permit is required to perform proposed work. The Department intends to issue this air construction permit based on the belief that the applicant has provided reasonable assurances to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C.

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit. The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the notice to be published as soon as possible after notification by the Department of its intended action. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114 / Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in Section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) and (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 thirty (30) days from the date of publication of Public Notice of Intent to Issue Air Permit. Written comments and 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. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. 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 (14) 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), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S. however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

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.

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. Mediation is not available in this proceeding. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

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

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

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

Executed in Tallahassee, Florida.

C. H. Fancy

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit package (including the Public Notice of Intent to Issue Air Construction Permit, 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 6/20/01 to the person(s) listed:

Mr. Ben Jacoby, Fort Pierce Re-Powering Project, LLC*
Mr. Scott Churbok, Enron North America Corporation
Mr. Tom Davis, ECT
Mr. Isidore Goldman, SED
Chair, St. Lucie Board of County Commissioners
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

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.

Charlotte J. Hayes 6/20/01
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Project No. 1110102-001-AC
Draft Permit PSD-FL-320

Fort Pierce Re-Powering Project, LLC
180 MW Combined Cycle Gas Turbine Project
Emissions Unit 001

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit to Fort Pierce Re-Powering Project, LLC (an affiliate of Enron North America) to construct a nominal 180 MW combined cycle gas turbine project. The new plant will be located adjacent to the existing H. D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. The applicant proposes to install one new combined cycle gas turbine-electrical generator set, a gas-fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air cooling, and other associated equipment. The project will produce a nominal 180 MW of electricity for sale to the power grid and sell steam to the H. D. King Plant to re-power existing steam turbine-electrical generators. The applicant's authorized representative is Mr. Ben Jacoby, Attorney-In-Fact for the Fort Pierce Re-Powering Project, LLC. The applicant's mailing address is 1400 Smith Street, Houston, TX 77002-7361.

Determinations of the Best Available Control Technology (BACT) were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC) in accordance with Rule 62-212.400, F.A.C., the Prevention of Significant Deterioration (PSD) of Air Quality. The combined cycle unit will be fired primarily with pipeline-quality natural gas and up to an equivalent of 1000 hours per year of low sulfur distillate oil as a backup fuel. The duct burners in the heat recovery steam generator will be fired exclusively with natural gas. Emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC will be minimized by the efficient combustion of low sulfur fuels. A catalytic oxidation system will further reduce CO and VOC emissions. A selective catalytic reduction system combined with dry low-NOx combustion technology (gas firing) and wet injection (oil firing) will reduce NOx emissions. The following table summarizes potential annual emissions after control from this project.

Pollutant	Emissions, (Tons Per Year)
CO	76
NOx	122
PM/PM_{10}	87
SAM	16
SO_2	95
VOC	46

The Department reviewed the air quality impact analysis conducted for emissions of CO, NO_2, PM_{10} and SO_2. Emissions of these pollutants from the project will not significantly contribute to, or cause a violation of, any state or federal ambient air quality standards. No PSD Class I impact analysis is required because the project is located 190 km north of the closest Class I area (Everglades National Park). No PSD Class II increment consumption analysis is required for CO because no PSD increments have been established for this pollutant. No PSD Class II increment consumption analysis is required for NO_2 or PM_{10} because the maximum predicted impacts are insignificant. Because SO_2 impacts were greater than the significant impact levels, multi-source modeling was conducted to evaluate the SO_2 impacts from the project combined with all other major sources in the vicinity. As shown in the following table, the maximum predicted SO_2 impacts are less than the allowable PSD Class II increments.

Pollutant	PSD Class II Increment Consumed ($\mu g/m^3$)	Allowable Increment ($\mu g/m^3$)	Increment Consumed, %
SO_2, 24-hour	30	91	33%
SO_2, 3-hour	81	512	16%

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

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue Air Construction Permit. Written comments and 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. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. 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, F.S. 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 (14) 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), F.S. must be filed within fourteen (14) days of publication of the public notice or within fourteen (14) days of receipt of this notice of intent, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within fourteen (14) 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, F.A.C.

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:

Florida Department of Environmental Protection
Bureau of Air Regulation
(111 S. Magnolia Drive, Suite 4)
2600 Blair Stone Road, MS #5505
Tallahassee, Florida, 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Florida Department of Environmental Protection
Southeast District Office, Air Resources Section
(400 North Congress Avenue)
P.O. Box 15425
West Palm Beach, FL 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

The complete project file includes the application, Technical Evaluation and Preliminary Determination, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. For additional information, interested persons may contact the Department's reviewing engineer for this project at the Bureau of Air Regulation at the address and phone number listed above.

NOTICE TO BE PUBLISHED IN THE NEWSPAPER

TECHNICAL EVALUATION & PRELIMINARY DETERMINATION
(Including Draft BACT Determinations)

PROJECT

Project No. 1110102-001-AC

Draft Permit No. PSD-FL-320

New 180 MW Combined Cycle Gas Turbine Project

COUNTY

St. Lucie County

APPLICANT

ENRON North America Corporation

Fort Pierce Re-powering Project, LLC

PERMITTING AUTHORITY

Florida Department of Environmental Protection

Division of Air Resources Management

Bureau of Air Regulation

New Source Review Section

June 18, 2001

{Filename: 320 TEPD.DOC}

1. GENERAL PROJECT INFORMATION

1.1 Applicant Name and Address

Fort Pierce Repowering Project, LLC
1400 Smith Street
Houston, TX 77002-7361

Authorized Representative:
Ben Jacoby, Attorney-In-Fact

1.2 Processing Schedule

04/19/01 Department received the application for a PSD air pollution construction permit.

04/25/01 Department mailed copies to EPA Region 4 and the National Park Service.

05/04/01 Department requested additional information.

05/16/01 Department received additional information making the application complete. {Note: The applicant modified the initial application by asking to remove the original request for simple cycle operation.}

05/22/01 Department received additional air quality modeling information making the application complete.

1.3 Facility Description and Location

The applicant proposes to construct a new 180 MW electrical generating plant consisting of a 180 MW gas turbine with electrical generator set and a heat recovery steam generator. The planned project will be located adjacent to the existing H.D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. This is an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). The UTM coordinates are Zone 17, 566.8 km East, and 3036.3 km North. This location is approximately 190 km from the nearest Class I area, the Everglades National Park.

1.4 Standard Industrial Classification Code (SIC)

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

Industry No. 4911, Electric Services

1.5 Regulatory Categories

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbine is subject to the acid rain provisions of the Clean Air Act.

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

PSD: The facility is a "fossil fuel steam electric plant with more than 250 mmBTU per hour of heat input", which is one of the 28 PSD source categories with lower emissions thresholds. Because potential emissions are greater than 100 tons per year for at least one regulated air pollutant, the facility is a major source of air pollution in accordance with the requirements of the Prevention of Significant Deterioration (PSD) of Air Quality Program (Rule 62-212.400, F.A.C.). Projects resulting in net emissions increases greater than the Significant Emissions Rates specified in Table 62-212.400-2, F.A.C. are subject to the PSD new source preconstruction review requirements.

NSPS: The New Source Performance Standards in 40 CFR 60 apply to the new gas turbine (Subpart GG) and the heat recovery steam generator with duct firing (Subpart Da).

{Note: Although the proposed new facility will be located adjacent to an existing major source, it is subject to PSD preconstruction review and determinations of Best Available Control Technology as a separate source. Accordingly, a determination of whether the two facilities are separate or not is considered moot for PSD purposes.}

1.6 Project Description

The applicant proposes construction of a new 180 MW gas turbine electrical generating plant in St. Lucie County. The new plant consists of: one Mitsubishi Model 501F gas turbine-electrical generator set; an automated gas turbine control system; an inlet air filtration system; an evaporative inlet air cooling system; a heat recovery steam generator with duct firing; an exhaust stack that is 142 feet tall and 20 feet in diameter; a selective catalytic reduction system; a catalytic oxidation system; and continuous monitoring systems. The new plant will be located adjacent to the existing H.D. King Plant owned and operated by the Fort Pierce Utilities Authority. It is designed to generate a nominal 180 MW of electricity for sale to the power grid and produce steam for sale to the existing H.D. King Plant to re-power two steam turbine-electrical generators. The gas turbine will be fired primarily with natural gas and very low sulfur distillate oil as a backup fuel (less than 1000 hours per year). The unit will only operate in combined cycle mode. Low-load operation is prohibited for operation below 50% load for gas firing and below 75% load for oil firing. When firing gas, operation between 50% and 75% load is limited to no more than 2000 hours per year. A dump condenser may be installed in the unlikely event that the H. D. King Plant's steam turbine-electrical generators go down. Emissions of particulate matter, sulfuric acid mist, sulfur dioxide, and volatile organic compounds will be minimized by the efficient combustion of very low sulfur fuels. The applicant proposes a catalytic oxidation system to control carbon monoxide emissions. In conjunction with dry low NOx technology for gas firing and wet injection for oil firing, a selective catalytic reduction (SCR) system is proposed for NOx control.

1.7 Potential Emissions

Table 1A. This table summarizes potential project emissions and the resulting PSD applicability.

Pollutant	PTE As Proposed [a] (Tons Per Year)	PTE Draft Permit [b] (Tons Per Year)	Significant Emissions Rate (Tons Per Year)	Significant? Table 62-212.400-2, F.A.C.	BACT Required?
CO	98	76	100	Yes [c]	Yes
NOx	128	122	40	Yes	Yes
PM/PM_{10}	87	87	25/15	Yes	Yes
SAM	17	16	7	Yes	Yes
SO_2	99	95	40	Yes	Yes
VOC	104	46	40	Yes	Yes

[a] The applicant's potential emissions were based on 7760 hours per year of gas firing, 1000 hours per year of oil firing, 100% load, and a compressor inlet temperature of approximately 32° F. (Potential CO emissions prior to control by catalytic oxidation are greater than 100 tons per year.)

[b] The Department's potential emissions were based on 7760 hours per year of gas firing (2000 hours per year of low load operation), 1000 hours per year of oil firing, 100% load, and a compressor inlet temperature of approximately 32° F.

[c] Before the application of BACT-level controls, CO emissions are estimated to be between 261 and 875 tons per year based on the requested operation and part-load conditions.

2. APPLICABLE REGULATIONS

2.1 State Regulations

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

Chapter	Description
62-4	Permitting Requirements
62-204	Ambient Air Quality Requirements, PSD Increments, and Federal Regulations Adopted by Reference
62-210	Required Permits, Public Notice and Comments, Reports, Stack Height Policy, Circumvention, Excess Emissions, Forms and Instructions,
62-212	Preconstruction Review, PSD Requirements, and BACT Determinations
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards Rule 62-296.405, F.A.C. – Fossil Fuel Steam Generators > 250 mmBTU of Heat Input
62-297	Test Methods and Procedures, Continuous Monitoring Specifications, and Alternate Sampling Procedures

2.2 Federal Regulations

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

Title 40, CFR	Description
Section 51.166	Requirements for State Implementation Plans, Prevention of Significant Deterioration
Section 52.21	Approval of State Implementation Plans, Prevention of Significant Deterioration
Part 60	New Source Performance Standards (NSPS) Subpart A - General Provisions Subpart Da – Electric Utility Steam Generating Units > 250 mmBTU per hour NSPS Subpart GG - Stationary Gas Turbines Applicable Appendices
Part 72	Acid Rain Permits
Part 73	Allowances
Part 75	Monitoring
Part 77	Acid Rain Program - Excess Emissions

2.3 General PSD Applicability

The Department regulates major air pollution sources in accordance with Florida's Prevention of Significant Deterioration (PSD) program, as approved by the EPA in Florida's State Implementation Plan and defined in Rule 62-212.400, F.A.C. A PSD review is required only in areas currently in attainment with the National Ambient Air Quality Standard (AAQS) or areas designated as "unclassifiable" for a given pollutant. A new facility is considered "major" with respect to PSD if it 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 PSD Major Facility Categories (Table 62-212.400-1, F.A.C.), or

- 5 tons per year of lead.

For new projects at PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Pollutant emissions from the project exceeding these rates are considered "significant" and the applicant must employ the Best Available Control Technology (BACT) to minimize emissions of each such pollutant and evaluate the air quality impacts. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several "significant" regulated pollutants

2.4 PSD Preconstruction Review Requirements

PSD preconstruction review consists of two parts. The first part requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to predict ambient impacts from the project; a comparison of predicted ambient impacts from the project with National Ambient Air Quality Standards and PSD Increments; an evaluation of the air quality impacts from the project upon soils, vegetation, wildlife, and visibility; and an assessment of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The purpose of the Air Quality Analysis is to determine whether or not the proposed project will have a significant impact on Class I and Class II Areas and determine whether or not emissions from the project contribute significantly to, or cause a violation of, any state or federal ambient air quality standards.

The second part requires the Department to establish the Best Available Control Technology (BACT) for each pollutant emitted in excess of the PSD Significant Emission Rates. The applicant reviews current control technologies and techniques for similar projects and proposes control options and emissions standards for the project. The Department reviews the information provided by the applicant with all other available information and makes a determination of the Best Available Control Technology (BACT) for each "significant" regulated pollutant. The BACT determination must be based on the maximum degree of emissions reduction that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project, taking into account energy, environmental and economic impacts. The Department shall also give consideration to:

- Any EPA determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

The EPA currently directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards regulated by 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts and stated policy for pollution prevention.

2.5 PSD Applicability for Project

The proposed new plant will be located in St. Lucie County, Florida, an area that is in attainment (or designated as unclassifiable) for all air pollutants subject to a National Ambient Air Quality Standard (NAAQS). As shown in Table 1A, the new plant is considered a PSD-major source because potential emissions of at least one regulated pollutant exceed 100 tons per year and the new plant is classified as a "fossil fuel steam electric plant with more than 250 mmBTU per hour of heat input", which is one of the 28 PSD source categories with a lower emissions threshold. Emissions of CO, NOx, PM/PM_{10}, SAM, SO_2, and VOC are significant and the Department is required to make determinations of the Best Available Control Technology (BACT) for these pollutants and review the applicant's air quality impact analysis.

3. DRAFT BACT DETERMINATIONS

3.1 Available Information

In addition to the information submitted by the applicant, the Department also relied on the following information to make these determinations:

- DOE web site information on Advanced Turbine Systems Project;
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines (1993);
- "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation; Prepared for the U.S. Department of Energy (November 5, 1999);
- AP-42, Section 3.1 for gas turbines (April 2000);
- Goal Line Environmental Technology Website: http://www.glet.com;
- Catalytica Website – www.catalytica-inc.com
- Recently issued Department permits for combined cycle gas turbine projects;
- A list of recent determinations for combined cycle gas turbine projects is provided in Table 3A at the end of Section 3;
- Emissions test data from the Department's ARMS database for FPL's Fort Lauderdale Units 5A and 5B and FPC's Hines Unit 1; (Although these units are Westinghouse Model 501F gas turbines, the Department believes they are substantially the same configuration because due to the historical relationship between Mitsubishi and Westinghouse gas turbine development.)
- Mitsubishi's technical information regarding emissions with dry low-NOx combustion technology; and
- Comments received from the National Park Service on May 15, 2001.

Note: The following sections summarize the applicant's proposed emissions and the Department's draft determinations of the Best Available Control Technology (BACT) for each PSD-significant pollutant. The BACT review is based on the combined emissions from the 180 MW gas turbine and duct firing (384 mmBTU per hour) in the heat recovery steam generator (HRSG). The proposed emissions standards include emissions from duct firing. The project must also meet the New Source Performance Standards (40 CFR 60) in Subpart GG for gas turbines as well as Subpart Da for duct burners.

3.2 Nitrogen Oxides (NOx)

Discussion of NOx Emissions

A gas turbine is sometimes referred to a "heat engine". In operation, hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Because of the high temperatures associated with combustion turbines, the primary pollutant of concern is nitrogen oxides or NOx. Uncontrolled NOx emissions from small turbines may range from 100 to 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd corrected to 15% oxygen). For large modern turbines, the Department estimates uncontrolled emissions in the range of 150 ppmvd corrected to 15% oxygen. The New Source Performance Standard (40 CFR 60, Subpart GG) regulating NOx emissions from gas turbines is 75 ppmvd corrected to 15% oxygen and ISO conditions, which must then be corrected for the fuel-bound nitrogen content and heat rate of the given unit.

Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable NO_2 molecule. Emissions of NOx are a result of the oxidation of nitrogen available in the combustion air (thermal and prompt NOx) and conversion of chemically bound nitrogen in the fuel (fuel-bound NOx). *Thermal NOx* forms in the high temperature area of the gas turbine combustor, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Prompt NOx* forms near the flame front as intermediate combustion products and is a relatively small fraction of total NOx in lean, near-stoichiometric combustors. However, prompt NOx may become an important consideration for units using dry low-NOx combustors and lean fuel mixtures due to the inherently lower thermal NOx contribution. *Fuel-bound NOx* forms from the combustion of fuels containing nitrogen. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Other factors that may also increase NOx emissions are combustion turbine loads and compressor inlet air conditions. In general, NOx emissions from gas turbines with dry low-NOx systems fluctuate during startup to approximately 50% to 70% of base load after which emissions begin to stabilize. This can be due to warming up a cold unit as well as the combustor air/fuel staging needed to achieve lean premix conditions suitable for dry low-NOx emissions. Higher NOx emissions also result from low ambient inlet temperatures. Cold air is denser than hot air, so the mass flow rate of air will be greater on a cold day than a hot day. Denser air requires more fuel combustion to raise the temperature of the higher mass, providing increased power production as well as emissions. Many new gas turbine projects take advantage of this concept by including evaporative coolers that will provide a slight power boost during warm weather. The evaporative coolers inject small amounts of water at high pressure, which evaporate and cool the ambient compressor inlet air. Again, firing more fuel to raise the temperature of the higher mass increases power production nearer to peak load conditions. However, emissions increases are relatively small and the maximum emissions rate still occurs on the coldest predicted day, which is usually not much less than 32° F in Florida.

Description of Available NOx Controls

The following technologies were identified as potentially applicable for the control of NOx from combustion turbines. A brief description of each technology is included with an estimated control efficiency based on an uncontrolled conventional gas turbine with NOx emissions of 150 ppmvd corrected to 15% oxygen.

Wet Injection (WI): Water or steam is injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, 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. Standard combustor designs with wet injection can generally achieve NOx emissions of 42/65 ppmvd for gas/oil firing. Advanced combustor designs generate lower NOx emissions to begin with and can tolerate greater amounts of water or steam injection before causing flame instability. Advanced combustor designs with wet injection can achieve NOx emissions of 25/42 ppmvd for gas/oil firing. Wet injection results in 60% to 80% control efficiencies. NSPS Subpart GG was developed around this technology in the late 1970's. Because dry low-NOx combustion technology does not yet achieve low NOx emissions when firing oil, wet injection remains a viable control technique for oil firing.

Dry Low-NOx Combustor Design (DLN): Efforts over the last ten years to minimize NOx emissions from gas turbines have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. The following is a general description of the four typical air/fuel combustion modes used to achieve lean premix combustion. In the primary mode, fuel is supplied only to the primary nozzles to ignite, accelerate, and operate the unit over a range of low- to mid-loads and up to a set combustion reference temperature. Once the first combustion reference temperature is reached, operation in a lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in a secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone. Finally, in the lean premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. Although fuel is supplied to both the primary and secondary nozzles in the premix mode, there is only flame in the secondary stage. Some models maintain a diffusion burner, which leads to higher NOx emissions. The full lean premix mode of operation typically occurs between 50% and 75% of base load and provides the lowest NOx emissions. Due to the intricate air and fuel staging necessary for dry low-NOx combustion, the automated gas turbine control system becomes a critical component of the overall system. Although research for oil firing continues, dry low-NOx combustion technology is currently only effective for firing natural gas. Dry low-NOx combustion technology can result in control efficiencies of 80% to 95%.

Conventional Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. For this reaction to proceed satisfactorily, the exhaust gas temperature must be maintained between 450° F and 850° F. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects capable of very low NOx emissions (< 3.5 ppmvd) with control efficiencies up to 98%.

In the past, catalyst materials were susceptible to poisoning by sulfur compounds. In Europe and Japan, new catalyst formulations have proven effective in resisting sulfur-induced performance degradation from firing fuel oil. Compared to the older alumina-based catalysts, the new catalysts are resistant to sulfur fouling at temperatures below 770°F (EPRI). Through 1998, Mitsubishi reports that SCR systems were installed on 40 utility boilers firing residual oil, 21 industrial boilers firing residual oil, and another 70 industrial boilers firing distillate oil. Likewise, Babcock & Wilcox reports satisfactory results with SCR systems installed on several large utility boilers for the Taiwan Power Company, which fire a wide range of coal as well as heavy fuel oil with sulfur contents up to 2.0% and 50 ppm of vanadium. 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.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) currently employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project and Kissimmee Utility Authority will install SCR on newly permitted Cane Island Unit 3. New combined cycle combustion turbine projects in Florida are normally considered to be prime candidates for SCR with NOx emission limits of 3.5 ppmvd. Limits as low as 2 ppmvd have been specified in the southwest part of the country. Table 3A at the end of Section 3 shows several recently permitted projects requiring SCR.

SCONOx™: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and is distributed through Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which is within the typical range of exhaust gas from heat recovery steam generator in a combined cycle unit. SCONOx™ can achieve control efficiencies in the 90% to 98% range.

The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx™. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two F-class units at Otay Mesa, approximately 15 miles S.E. of San Diego, California. Additionally, USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with a SCONOx™ system.

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. In addition to the reduction of NOx, advantages of the SCONOx™ system include the elimination of ammonia and the additional control of CO and VOC emissions. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently due only to cost considerations. The Department is interested in seeing this ammonia-free emissions technology demonstrated on a large F-class unit.

XONON™: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flame-less catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but is specific to each manufacturer and model of gas turbine due to the unique combustor design. It is anticipated that control efficiencies will be in the 80% to 95% range. This emerging technology is model-specific and not yet commercially available for an F-class unit.

Applicant's Proposed NOx Controls

The applicant recognizes the SCONOX™ and SCR systems combined with dry low-NOx (DLN) combustion technology (gas firing) and wet injection (oil firing) as the top two control options. The applicant states that these technologies will result in the following adverse impacts.

Energy Impacts: A SCONOx™ system will cause a pressure drop of approximately 5 inches of water resulting in a 1% energy penalty due to reduced power output. An SCR system will cause a pressure drop of approximately 1.5 inches of water resulting in a 0.3% energy penalty due to reduced power output.

Environmental Impacts: An SCR system will result in collateral emissions of ammonia, ammonium bisulfate, and ammonium sulfate particulate matter.

Economic Impacts: The following table summarizes the applicant's cost analysis for each control option.

Control Option	Emissions TPY [a]	Reduction TPY [b]	Capital Costs $	Annualized Costs, $/yr	Cost Effectiveness, $/ton NOx removed	
					Average	Incremental [c]
SCONOx™	65	752	$12,092,710	$7,427,631	$9883/ton NOx	$88,827/ton
SCR	134	683	$3,864,831	$1,505,552	$2205/ton NOx	NA
Model 501F	817	NA	NA	NA	NA	NA

Notes:

a - Emissions based on 7760 hours per year of gas firing and 1000 hours per year of oil firing.

b - Emissions reductions based on 92% control efficiency for SCONOx™ and 86% (71.5%) control efficiencies for SCR with gas (oil) firing.

c - The incremental cost effectiveness is a measure of the additional cost ($) to provide the additional NOx reductions (TPY) of a SCONOx™ system over an SCR system.

Based on the cost analysis presented above, the applicant rejects SCONOx™ as not being cost effective for this project and accepts SCR as the next best available control option.

Applicant's Proposal: The applicant proposes the following emissions standards based on an SCR system combined with dry low-NOx combustion technology for gas firing and wet injection for oil firing.

Gas: 3.5 ppmvd corrected to 15% oxygen, 24-hour block average

Oil: 12.0 ppmvd corrected to 15% oxygen, 24-hour block average

Department's Draft BACT Determination for NOx Emissions

The Department also recognizes SCONOx™ and SCR as the top two control options for combined cycle gas turbine projects. Although the Department does not endorse nor contest the applicant's cost analysis, it believes that the SCONOx™ system is not quite cost effective for this project.

Draft NOx BACT Determination: The Department determines the following emissions standards to represent BACT for NOx emissions based on an SCR system combined with dry low-NOx combustion technology when firing natural gas as the primary fuel and combined with wet injection when firing a restricted amount of distillate oil as a backup fuel.

Gas, > 50% load: 3.5 ppmvd corrected to 15% oxygen, 3-hour rolling CEMS average

Oil, > 75% load 10.0 ppmvd corrected to 15% oxygen, 3-hour rolling CEMS average

This determination is consistent with recent BACT determinations for combined cycle units made in Florida and other states. The NOx limit for oil firing was specified as 10 ppmvd compared to the applicant's requested 12 ppmvd. This is because the control efficiency of the SCR system is expected to be closer to 80% when firing oil and not 70% as predicted by the applicant. The applicant later agreed to the proposed lower limit. The draft BACT standards are much more stringent than the NSPS standard in Subpart GG in 40 CFR 60. Compliance with the standards shall be demonstrated by data collected from a NOx continuous emissions monitor (CEMS) certified in accordance with Performance Specification 2.

3.3 Carbon Monoxide CO

Discussion of CO Emissions

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion. In general, CO emissions are inversely proportional to NOx emissions from gas turbines. However, new advanced combustor designs have also greatly reduced CO emissions concurrently with NOx emissions. Catalytic oxidation systems or efficient combustion designs are typically used to minimize CO emissions from gas turbine projects. Catalytic oxidation systems can achieve emissions reductions greater than 90% depending on the uncontrolled VOC concentration.

Applicant's Proposed CO Controls

The manufacturer's information indicates that CO emissions for gas firing will likely be less than 15 ppmvd for 75% to 100% load conditions, but will increase to 80 ppmvd at loads near 50%. For oil firing, CO emissions are approximately 50 ppmvd for 75% to 100% load conditions, but can increase to as much as 1000 ppmvd at loads near 50%. Because some operation at low loads is desired when firing natural gas, the applicant proposes to install the top control option, a catalytic oxidation system. The applicant only requests operation at loads greater than 75% when firing distillate oil because of the elevated CO emissions. (Note: All concentrations are corrected to 15% oxygen.)

Applicant's Proposal: The applicant proposes the following CO standards based on the installation of a catalytic oxidation system.

Gas, > 75% load: 3.5 ppmvd corrected to 15% oxygen, 24-hour average

Gas, 50-75% load: 10.6 ppmvd corrected to 15% oxygen, 24-hour average

Oil, > 75% load (only): 10.0 ppmvd corrected to 15% oxygen, 24-hour average

Department's Draft BACT Determination for CO Emissions

For the Mitsubishi Model 501F, it is estimated that potential *uncontrolled* CO emissions could range from 261 to 875 tons per year. The Department recognizes a catalytic oxidation system as the top control option for CO emissions. Based on the maximum uncontrolled emissions predicted by Mitsubishi, the proposed emission standards represent the following control efficiencies: 78% control for gas firing above 75% load, 85% control for gas firing from 50-75% load, and 80% for oil firing above 75% load. The Department believes that control efficiencies of more than 90% can be achieved, particularly at the higher concentrations (AP-42, Section 3.1.4.3, April 2000). Because little actual emission data is available for the Mitsubishi Model 501F, the Department researched two Florida plants operating a "sister unit", the Westinghouse Model 501F. These plants include FPL's Fort Lauderdale Units 5A and 5B installed in 1993 and FPC's Hines Unit 1 installed in 1998. Over eleven tests, CO emissions were measured from 0.36 to 7 ppmvd for gas and oil firing at about 100% load without additional control.

Draft CO BACT Determination: The Department establishes the following CO standards as BACT for this project.

Gas, > 75% load: 3.5 ppmvd corrected to 15% oxygen, 24-hour block CEMS average

Gas, 50-75% load: 10.0 ppmvd corrected to 15% oxygen, 24-hour block CEMS average

Oil, > 75% load (only): 8.0 ppmvd corrected to 15% oxygen, 24-hour block CEMS average

The proposed limits are based on lower expected actual emissions as well as higher expected control efficiencies. If the unit is operated at both load conditions during a 24-hour period, the limits shall be prorated based on operating hours within each load range. The applicant later agreed to the proposed lower standards. Compliance with the standards shall be demonstrated by data collected from a CO continuous emissions monitor (CEMS) certified in accordance with Performance Specification 4.

3.4 Particulate Matter (PM/PM_{10}), Sulfuric Acid Mist (SAM), and Sulfur Dioxide (SO_2)

Discussion of PM/PM_{10}, SAM, and SO_2 Emissions

Emissions of particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2) will result from the combustion of natural gas and distillate oil. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Sulfuric acid mist and sulfur dioxide emissions will increase with higher fuel sulfur contents. However, natural gas and very low sulfur distillate oil contain little ash, sulfur, or other contaminants.

Applicant's Proposed PM/PM_{10}, SAM, and SO_2 Controls

The applicant proposes natural gas as the primary fuel with very low sulfur distillate oil as a backup fuel to minimize emissions of PM/PM_{10}, SAM, and SO_2. In addition, these clean fuels are required to prevent damage to turbine blades and other high-precision turbine components. Several available control technologies are identified for particulate matter removal including centrifugal collectors, electrostatic precipitators, fabric filters, and wet scrubbers. Similarly, there are acid gas scrubbing systems available to further reduce SAM and SO_2 emissions. The applicant notes that these types of post-control devices have never been applied to gas turbines. The applicant believes that the low pollutant concentrations and large volumetric flow rates would result in low control efficiencies and prohibitive costs.

Applicant's Proposal: The applicant proposes the following fuel specifications and opacity standard:

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF of natural gas

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

Gas and Oil: 10% opacity

Department's Draft BACT Determinations for PM/PM$_{10}$, SAM, and SO_2 Emissions

The Department believes that, although the control options are technically feasible, further control of these pollutants would be cost prohibitive due to the very low uncontrolled emissions. The fuel sulfur limits proposed are clearly more stringent than the NSPS standard of 0.8% sulfur by weight. The specification of clean fuels constitutes a pollution prevention technique and is given favorable consideration for this project.

Draft PM/PM$_{10}$, SAM, and SO_2 BACT Determinations: The Department establishes the following fuel specifications and standards as the draft BACT for PM/PM$_{10}$, SAM, and SO_2.

Gas: Pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 SCF of natural gas

PM ≤ 17.0 pounds per hour

Oil: No. 2 distillate oil with a maximum of 0.05% sulfur by weight

PM ≤ 42.5 pounds per hour

Gas and Oil: Visible emissions shall not exceed 10% opacity based on a 6-minute average.

Limiting the fuel sulfur content establishes the maximum potential emissions of SAM and SO_2 so that additional emissions standards are unnecessary. An initial test shall be performed to demonstrate compliance with the particulate matter emissions standards. Thereafter, compliance with the fuel specifications, opacity standard, and CO standards will serve as indicators of good combustion practices. Compliance with the fuel sulfur limits shall be demonstrated by maintaining the fuel quality records.

3.5 Volatile Organic Compounds (VOC)

Discussion of VOC Emissions

VOC emissions result from incomplete combustion when firing natural gas and distillate oil. Large combustion turbines offer high temperatures with efficient combustion resulting in relatively low levels of volatile organic compounds. Catalytic oxidation systems or efficient combustion designs are typically used to minimize VOC emissions from combustion turbines. Catalytic oxidation systems can achieve emissions reductions greater than 80% depending on the uncontrolled VOC concentration.

Applicant's Proposed VOC Controls

The manufacturer's information indicates that VOC emissions from gas firing will likely be less than 2 ppmvd for 75% to 100% load conditions, but will increase to 35 ppmvd at loads near 50%. For oil firing, VOC emissions are approximately 15 ppmvd for 75% to 100% load conditions, but can increase to 60 ppmvd at loads near 50%. The applicant already proposes to install a catalytic oxidation system to control CO emissions, which is also the top control option to reduce VOC emissions. Again, the applicant requests operation only at loads greater than 75% when firing distillate oil. (Note: All concentrations are corrected to 15% oxygen.)

Applicant's Proposal

Gas, 50-75% load: 22.3 ppmvd corrected to 15% oxygen

Gas, > 75% load: 2.2 ppmvd corrected to 15% oxygen

Oil, >75% load (only): 10.0 ppmvd corrected to 15% oxygen

Department's Draft BACT Determinations for VOC Emissions

The Department agrees that the top control option to reduce VOC emissions is a catalytic oxidation system. However, similar to CO emissions control, the Department believes the proposed standards overestimate uncontrolled VOC emissions and underestimate the control efficiency of such a system. For ten tests on similar units (FPL's Fort Lauderdale Units 5A and 5B installed in 1993 and FPC's Hines Unit 1 installed in

1998), VOC emissions ranged from 0.05 to 0.8 ppmvd for gas and oil firing at about 100% load without additional control. Also, the Department believes that VOC control efficiencies of more than 80% can be achieved, particularly at the high concentrations estimated for the Mitsubishi Model 501F. (AP-42, Section 3.1.4.3, April 2000).

Draft VOC BACT Determinations: The Department establishes the following standards as draft BACT for VOC emissions.

Gas, 50-75% load: 16.0 ppmvd corrected to 15% oxygen

Gas, > 75% load: 2.2 ppmvd corrected to 15% oxygen

Oil, > 75% load: 10.0 ppmvd corrected to 15% oxygen

The proposed limits are based on lower expected actual emissions as well as higher expected control efficiencies. When firing natural gas, operation between 50% and 75% of base load will be restricted to no more than 2000 hours during any consecutive 12 months. The combined VOC standards result in a weighted average of 6.2 ppmvd based on 1000 hours of oil firing, 2000 hours of low load gas firing, and 5760 hours of gas firing above 75% base load. The applicant later agreed to the proposed lower standards. In addition, the applicant agreed that the standards could be lowered (if appropriate) in the final permit based on final vendor guarantees. The Compliance with these standards shall be based on initial performance tests, as determined by EPA Method 25A reported in terms of methane. Optionally, EPA Method 18 may also be conducted concurrently with EPA Method 25A to deduct non-regulated emissions of methane and ethane. Thereafter, compliance with the continuous CO standards shall serve as indicators of good combustion. Subsequent VOC emissions performance tests shall only be required when the Department has good reason to believe that a VOC emission standard is being violated pursuant to Rule 62-297.310(7)(b), F.A.C.

Table 3A. Summary of Recent BACT Determinations for Combined Cycle Gas Turbine Projects (≈ 170 MW)

Project Location	Date	CT Model	Unit MW	Control Technologies	CO Limit ppmvd @ 15% O2	NOx Limit ppmvd @ 15% O2	PM Limit	SO2 Limit	VOC Limit ppm
Hinds Energy, MS	01/00	GE 7FA?	170	SCR w/DLN	20, gas	3.5, gas	NI	NI	NI
Attala Energy, MS	02/00	GE 7FA?	170	SCR w/DLN	20, gas	3.5, gas	NI	NI	NI
Calpine Delta, CA (LAER)	02/00	GE 7FA or S/W 501FD	170	SCR w/DLN	10, gas w/DB (3-hr CEMS avg.)	2.5, gas w/DB	0.25 gr. S/100 SCF of natural gas	NI	2, gas
Calpine Bullhead City,	02/00	S/W 501FD	170	SCR w/DLN	10, gas w/DB (3-hr CEMS avg.)	3.0, gas w/DB	18.3 lb/hr 22.8 lb/hr w/DB/PA	NI	1.5, gas
Mobile Energy, AL	03/00	GE 7FA	170	SCR w/DLN/WI	18, gas w/DB 26, oil w/DB	3.5, gas w/DB 11, oil w/DB	10% opacity Good Combustion	NI	5, gas 6, oil
GPC Boat Rock, AL	04/00	GE 7FA	170	SCR w/DLN	30, gas w/DB	3.5, gas w/DB	NI	NI	8, gas w/DB
CPV Gulfcoast, FL	02/01	GE 7FA	170	SCR w/DLN/WI	9, gas 15, gas w/PA 20, oil	3.5, gas 10, oil	10% opacity	LSF	1.4, gas 3.6, oil
TEC Bayside, FL (BACT for CO/PM/PM10/VOC only)	03/01	GE 7FA	170	SCR w/DLN/WI	8, gas 20, oil	3.5, gas 12, oil	10% opacity	LSF	1.3, gas 3, oil
Calpine Osprey, FL	Draft	S/W 501FD	170	SCR w/DLN	10, gas 17, gas w/DB/PA	3.5, gas	10% opacity	LSF	2.3, gas 4.6, gas w/DB/PA
Calpine Blue Heron, FL	Draft	S/W 501FD	170	SCR w/DLN	10, gas 17, gas w/DB/PA	3.5, gas	10% opacity	LSF	1.2, gas 6.6, gas w/DB/PA
FPC Hines Power Block II, FL	Draft	S/W 501FD	170	SCR w/DLN/WI	16, gas 30, oil	3.5, gas 12, oil	7.3 lb/hr, gas 64.8 lb/hr, oil	LSF	2, gas 10, oil
CPV Atlantic, FL	Draft	GE 7FA	170	SCR w/DLN/WI	9, gas 15, gas w/PA 20, oil	3.5, gas 10, oil	10% opacity	LSF	1.4, gas 3.6, oil
JEA Brandy Branch - Baldwin, FL	Draft	GE 7FA	170	SCR w/DLN/WI	14, gas or oil	3.5, gas 15, oil	10% opacity	LSF	No BACT
OUC/KUA/FMPA Southern Co., FL Stanton Unit A	Draft	GE 7FA	170	SCR w/DLN/WI	14, gas 17, oil	3.5, gas 10, oil	10% opacity	LSF	2.7, gas 6.3, oil
Enron Fort Pierce Re-Powering, FL	Pending	Mitsubishi 501F	170	SCR w/DLN/WI	3.5, gas 10, gas low load 8, oil	3.5, gas 10, oil	10% opacity	LSF	2.2, gas 16, low load 10, oil

Table Notes:

- Data presented is for combined cycle units with an approximate direct electrical generation of 170 MW and includes only those projects with a draft or final permit.
- "DLN" means dry low-NOx combustion technology. "SCR" means a selective catalytic reduction system. "OC" means a catalytic oxidation system. "CEMS" means a continuous emissions monitoring system.
- Some units have other modes of operation that are not listed in the above table, such as steam injection for power augmentation, high temperature peaking, or simple cycle operation. Low load operation for the Enron Fort Pierce Repowering Project means operation between 50% and 75% of base load.

4. NSPS STANDARDS

4.1 40 CFR 60, Subpart GG - Gas Turbines

In the late 1970's, EPA developed New Source Performance Standards (NSPS) for stationary gas turbines. This regulation established minimum performance and monitoring standards for emissions of nitrogen oxides (NOx) and sulfur dioxide (SO_2) for new gas turbines. For the proposed project, the NSPS standards would be:

NOx: 108 ppmvd corrected to 15% oxygen when firing natural gas, and

102 ppmvd corrected to 15% oxygen when firing distillate oil

SO_2: fuel oil containing less than 0.8% sulfur by weight

By definition, BACT standards are considered to be more stringent than the NSPS requirements. The draft NOx and SO_2 BACT standards established in the previous section are clearly much more stringent that the applicable NSPS standards.

4.2 40 CFR 60, Subpart Da – Duct Burners

Also in the late 1970's, EPA developed New Source Performance Standards (NSPS) for electric utility steam generating units. The regulation established minimum performance and monitoring standards for emissions of particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and nitrogen oxides (NOx) for large utility boilers. The regulation also applies to heat recovery steam generators (HRSGs) with duct firing on combined cycle units until EPA develops appropriate standards in Subpart GG for gas turbines. In 1998, EPA modified this rule to include a NOx emissions limit of 1.6 lb per MW-hour of gross energy output (30-day rolling average) for units constructed after July 9, 1997. With control by the SCR system, it is estimated that emissions from the proposed project will be less than 0.1 lb per MW-hour for gas firing and 0.4 lb per MW-hour for oil firing. On April 10, 2001, EPA published a revision to this regulation, which becomes effective on June 11, 2001. The change simplifies monitoring and compliance procedures for HRSGs with duct burners. Consistent with the rule change, the applicant proposes to continuously monitor the combined NOx emission rate and gross energy output to demonstrate compliance.

5. EXCESS EMISSIONS

Based on the design of the gas turbine and Rules 62-210.700 and 62-4.130, F.A.C., the following conditions will be included in the permit to address periods of excess emissions.

5.1 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 emissions shall be included in any compliance demonstration based on continuous monitoring data.

5.2 Excess Emissions Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for during specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

b. *Low Load Restriction*: When firing natural gas, operation below 50% load is prohibited, excluding startups and shutdowns. When firing natural gas and operating between 50% and 75% of base load, the gas turbine shall not operate more than 2000 hours during any consecutive 12 months. When firing distillate oil, operation below 75% load is prohibited, excluding startups and shutdowns.

c. *CO and NOx CEMS Data Exclusion*: Except for combined cycle cold startups, no more than two (2) hourly average emission rate values shall be excluded from the continuous compliance demonstrations due to startup, shutdown, or documented unavoidable malfunction. No more than four (4) hourly average emission rate values shall be excluded from the continuous compliance demonstrations due to combined cycle cold startups. No more than a total of four (4) hourly average emission rate values shall be excluded from the continuous compliance demonstrations for all such episodes in any calendar day. A "combined cycle cold startup" is defined as startup after the combined cycle gas turbine has been shutdown for 48 hours or more. A "documented unavoidable malfunction" is a malfunction beyond the control of the operator that is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

6. AIR QUALITY IMPACT ANALYSIS

6.1 Summary

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, SAM and VOC. PM_{10}, SO_2 and NO_x are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments, AAQS or de minimis monitoring levels for SAM; the BACT determination will limit maximum potential SAM emissions. Potential emissions for VOC are above the 40 TPY significance threshold for the pollutant ozone. The applicant presented the potential increases to the Department, but based on the options available to predict potential impacts associated with the emissions and formation of ozone, the Department has determined that the use of regional models which incorporate the complex chemical mechanisms for predicting ozone formation are not feasible for this project.

The applicant's initial PM/PM_{10}, CO and NO_x, air quality impact analyses for this project predicted no significant impacts in the Class II area in the vicinity of the project. Therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required in the Class II area. No impacts on the Everglades National Park, the closest PSD Class I area, were calculated since the project is located 180 km north of this area.

Also, the maximum predicted impacts for all pollutants were below their respective de minimis ambient impact levels. Therefore, pre-construction monitoring at the proposed site was not required for this project. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project were the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_2 in the surrounding Class II Area;
- A PSD increment analysis for SO_2;
- An Ambient Air Quality Standards (AAQS) analysis for SO_2;
- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

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

6.2 Ambient Monitoring Requirements

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. When available, the use of existing representative monitoring data may satisfy the monitoring requirement. An exemption to the monitoring requirement may be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis concentration. No de minimis ambient concentration is provided for ozone. Instead the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year. The table below shows that predicted ambient impacts from the power plant are substantially less than the respective de minimis levels; therefore, preconstruction ambient air quality monitoring is not required for any pollutant.

Predicted Maximum Air Quality Impacts from the Project Compared to the De Minimis Ambient Impact Levels				
Pollutant	Averaging Time	Max. Predicted Impact, ug/m^3	De Minimis Level, ug/m^3	Impact > De Minimis?
PM_{10}	24-hour	3	10	No
NO_2	Annual	0.4	14	No
SO_2	24-hour	11	13	No
CO	8-hour	10	575	No
VOC	Annual Emission Rate	< 100 TPY	100 TPY	No

The highest 3-hour and 24-hour SO_2 averages from the Palm Beach County Health Department's SO_2 monitoring site located in Riviera Beach were used as background concentrations in the SO_2 AAQS analysis. These SO_2 concentrations are shown in the table below.

Background Concentrations for Use in AAQS Analyses		
Pollutant	Averaging Time	Background Concentration (μg/m^3)
SO_2	24-hour	34
	3-hour	178

6.3 Models and Meteorological Data Used in the Air Quality Analysis

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 and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all 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 the National Weather Service (NWS) station at West Palm Beach, Florida (surface and upper air data). The 5-year period of meteorological data was from 1987 through 1991. This NWS 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.

6.4 Significant Impact Analysis

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 highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels. If this modeling at worst-case load conditions shows significant impacts, additional modeling which includes the emissions from surrounding facilities is required to determine the project's impacts on the existing air quality and any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

A combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals along the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at 100 meters from the fenceline and extending to 1000 meters from the site. Beyond 1,000 meters, a polar receptor grid was used with radial spacing of 100 meters out to 2,000 meters. From 2,000 to 4,000 meters, a polar receptor grid with radial spacing of 250 meters was used. Between 4,000 and 10,000 meters, a polar receptor grid with radial spacing of 1 kilometer was used. The modeling approach was based on the assumption that a refined receptor grid (minimum 100 meter spacing) would be used as necessary in order to determine maximum predicted concentrations in various areas of the initial grid.

Predicted Maximum Air Quality Impacts from the Project Compared to the PSD Class II Significant Impact Levels in the Vicinity of the Project

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Levels (ug/m^3)	Significant Impact?
SO_2	Annual	0.4	1	No
	24-hour	11	5	Yes
	3-hour	25	25	Yes
PM_{10}	Annual	0.1	1	No
	24-hour	3	5	No
CO	8-hour	7	500	No
	1-hour	54	2000	No
NO_2	Annual	0.4	1	No

The results of the significant impact modeling show that there are no significant impacts predicted due to PM_{10}, CO and NOx emissions from this project in the vicinity of the facility; therefore, no further modeling was required in the Class II area for these pollutants. As shown in the table the maximum predicted air quality impacts due to SO_2 emissions from the proposed project are greater than the PSD significant impact levels. Therefore, the applicant was required to do full impact SO_2 modeling within the applicable significant impact area to determine the impacts of the project along with all other sources in the vicinity of the facility.

6.5 PSD Increment Analysis

The PSD increment represents the amount that sources constructed after the PSD Baseline dates, (February 8, 1988 for NO_2 and January 6, 1975 for PM_{10} and SO_2), may increase ambient ground level concentrations of a pollutant. The results of the required PSD Class II increment analyses presented in the table below show that all of the maximum predicted impacts are less than the allowable Class II increments.

PSD Class II Increment Analysis					
Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Impact Greater than Allowable Increment?	Allowable Increment (μg/m^3)	Project Impact Percent of Increment
SO_2	24-hour	30	No	91	33%
	3-hour	81	No	512	16%

6.6 AAQS Analysis

For pollutants subject to an AAQS review, the total impact on ambient air quality is obtained by adding a "background" concentration to the maximum-modeled concentration. This "background" concentration takes into account all sources of a particular pollutant that are not explicitly modeled. The results of the AAQS analysis are summarized in the table below. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any AAQS.

Ambient Air Quality Impacts						
Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Concentration (μg/m^3)	Total Impact (μg/m^3)	Total Impact Greater than AAQS?	Florida AAQS (μg/m^3)
SO_2	24-hour	30	34	64	No	260
	3-hour	81	178	259	No	1300

6.7 Additional Impacts Analysis

Impact on Soils, Vegetation, And Wildlife

Very low emissions are expected from the natural gas and distillate oil fired gas turbine 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, NOx, 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. In addition, the project impacts for PM_{10}, CO and NOx are less than the significant impact levels, which, in turn, are less than the applicable allowable increments for each pollutant. The AAQS are designed to protect both the public health and welfare. 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.

Impact On Visibility and Regional Haze

Natural gas and low sulfur distillate fuel oil are clean fuels and produce little ash. This will minimize smoke formation. The low NOx and SO_2 emissions will also minimize plume opacity. The contribution to smog in the area will be minimal.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the unit will require few permanent employees, which will cause no significant impact on the local area. The proposed project has a small overall physical "footprint" and among the lowest air emissions per unit of electric power generating capacity.

Hazardous Air Pollutants

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

7. 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 Analysis, and the conditions specified in the draft permit. Cleve Holladay is the project meteorologist responsible for reviewing and validating the Air Quality Analysis for the project. Jeff Koerner is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DRAFT PERMIT

PERMITTEE:

Fort Pierce Re-Powering Project, LLC
1400 Smith Street
Houston, TX 77002-7361

Authorized Representative:
Ben Jacoby, Attorney-In-Fact

Project No. 1110102-001-AC
Air Permit No. PSD-FL-320
Facility ID No. 1110102
SIC No. 4911
Expires: January 30, 2003

PROJECT AND LOCATION

This permit authorizes the construction of a new nominal 180 MW electrical generating plant, the Fort Pierce Re-Powering Project, to be located adjacent to the existing H.D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. The Fort Pierce Utilities Authority owns and operates the existing H.D. King Plant and has no ownership in, or control over, the proposed new plant. The plant will consist of one combined cycle gas turbine and associated equipment. The UTM coordinates are Zone 17, 566.8 km East, and 3036.3 km North.

STATEMENT OF BASIS

This PSD air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Part 52, Section 21 of the Code of Federal Regulations. Specifically, this permit is issued pursuant to the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality, Rule 62-212.400, F.A.C. 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

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

FACILITY DESCRIPTION

The proposed project is for a new electrical power plant, the Fort Pierce Re-Powering Project, LLC, which will generate a nominal 180 MW of electricity and sell steam to the existing H.D. King Plant to re-power their existing steam electrical generators. The proposed new plant consists of one 180 MW combined cycle gas turbine and associated equipment.

NEW EMISSIONS UNITS

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

ID	Emission Unit Description
001	**Combined Cycle Unit No. CC-1** consists of a Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set (180 MW), a fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air cooling, and other associated equipment.

REGULATORY CLASSIFICATION

Title III: Based on available data, the new facility is not a major source of hazardous air pollutants (HAP).

Title IV: The new gas turbine is 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 new facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C. Regulated pollutants include pollutants such as carbon monoxide (CO), nitrogen oxides (NOx), 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" 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 major source of air pollution with respect to Rule 62-212.400, F.A.C, the Prevention of Significant Deterioration (PSD) of Air Quality.

PPSC: This project is not subject to Chapter 62-17, F.A.C. for Power Plant Site Certification because there will be no net increase in steam generated electrical power.

NSPS: The New Source Performance Standards in 40 CFR 60 apply to the new gas turbine (Subpart GG) and the heat recovery steam generator with duct firing (Subpart Da).

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.

COMPLIANCE AUTHORITIES

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Resources Section of the Department's Southeast District Office at P.O. Box 15425 (400 North Congress Avenue) in West Palm Beach, Florida 33416-5425.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix CF. Citation Format

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 XS. Continuous Monitor Systems Quarterly 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 April 20, 2001 and all related correspondence to make complete.
- Draft permit package issued on (Draft)
- Comments received from the public, the applicant, the Southeast District Office, the EPA Region 4 Office, and the National Park Service.

CITATION FORMAT

Appendix CF of this permit describes the format used to cite applicable rules and regulations as well as previous permitting actions.

1. General Conditions: The owner and operator are subject to, and 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. PSD Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

4. Permit Expiration: 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, and 62-210.300(1), F.A.C]

5. BACT Determination: In conjunction with an extension of the 18-month period to commence or continue construction, phasing of the project, or an extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of Best Available Control Technology (BACT) for the source. [Rule 62-212.400(6)(b), F.A.C. and 40 CFR 51.166(j)(4)]

6. 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.]

7. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

8. 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 Region 4 Office of the U.S. Environmental Protection Agency in Atlanta, Georgia and a copy to the Department's Bureau of Air Regulation in Tallahassee. [40 CFR 72]

9. Title V Permit: This permit authorizes construction of the permitted emissions units and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Department's Bureau of Air Regulation, and copies to each Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

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

Emissions Unit No. 001: Combined Cycle Gas Turbine No. CC-1
Description: The combined cycle unit consists of a Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set with a nominal capacity of 180 MW, a fired heat recovery steam generator (384 mmBTU per hour), a selective catalytic reduction system, and a catalytic oxidation system. Ancillary equipment includes an automated gas turbine control system, an inlet air filtration system, monitoring systems, and an inlet air-cooling system. *Fuel*: The combined cycle unit is fired primarily with pipeline-quality natural gas and very low sulfur distillate oil as a backup fuel. *Capacity*: At a compressor inlet air temperature of 32° F, the combined cycle gas turbine produces approximately 185 MW when firing approximately 1998 mmBTU (HHV) per hour of natural gas. At a compressor inlet air temperature of 32° F, the combined cycle gas turbine produces approximately 166 MW when firing approximately 1821 mmBTU (HHV) per hour of natural gas. *Controls*: The efficient combustion of very low sulfur fuels at high temperatures minimizes emissions of CO, PM/PM_{10}, SAM, SO_2, and VOC. A catalytic oxidation system further reduces emissions of CO and VOC. Combined with dry low-NOx (DLN) combustion technology when firing natural gas and wet injection when firing distillate oil, a selective catalytic reduction (SCR) system reduces NOx emissions. *Stack Parameters*: When firing natural gas at 100% load with a compressor inlet temperature of 59° F, exhaust gases exit a 20.0 feet diameter stack that is 142 feet tall with a flow rate of approximately 2,465,000 acfm at 287° F.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emissions standards specified for this unit represent Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), 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 emissions performance and monitoring requirements of Section 3A also demonstrates compliance with the New Source Performance Standards in 40 CFR 60 for gas turbines (Subpart GG) and heat recovery steam generator with duct firing (Subpart Da). For completeness, the applicable Subpart GG and Subpart Da requirements are included in Appendix Da and Appendix GG of this permit. [Rule 62-4.070(3), F.A.C.]

EQUIPMENT

3. Combined Cycle Gas Turbine: The permittee is authorized to install, tune, maintain and operate a new combined cycle unit consisting of: a Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set; an automated gas turbine control system; filtration and cooling systems for the compressor inlet air; a fired (384 mmBTU per hour) heat recovery steam generator (HRSG); a selective catalytic reduction system; a catalytic oxidation system; emissions monitoring systems; a stack that is 20.0 feet in diameter and 142 feet tall; and other miscellaneous support equipment. The combined cycle unit shall be designed as a system to generate a nominal 180 MW of shaft-driven electrical power and to sell steam from the HRSG to the existing H.D. King Plant. The permittee may install a dump condenser that will allow

combined cycle operation with full emissions control should the H.D. King Plant be unable to accept steam. [Applicant Request; Design]

4. DLN Combustion Technology and Wet Injection: The permittee shall tune and maintain the Mitsubishi dry low-NOx combustion system to minimize NOx emissions from the gas turbine when firing natural gas. The permittee shall tune, operate and maintain a wet injection system to minimize NOx emissions from the gas turbine when firing distillate oil. Prior to the initial emissions performance tests for each gas turbine, each control system shall be tuned along with the automated gas turbine control system to minimize NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. [Design; Rule 62-212.400 (BACT), F.A.C.]

5. SCR System: The permittee shall install, tune, maintain and operate a selective catalytic reduction (SCR) system to control NOx emissions from the combined cycle gas unit when firing either fuel. The SCR system consists of an ammonia injection grid, catalyst bed, aqueous ammonia storage, monitoring and control system, electrical, piping and other auxiliary equipment. The SCR system shall be designed to reduce NOx emissions below permitted levels while minimizing ammonia slip. [Rule 62-212.400 (BACT), F.A.C.]

6. Catalytic Oxidation System: The permittee shall install, maintain and operate a catalytic oxidation system to control CO and VOC emissions from the combined cycle unit when firing either fuel. It consists of an additional catalyst bed and support framework. The system shall be designed and maintained to reduce CO and VOC emissions below the permitted levels. [Rule 62-212.400 (BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

7. Permitted Capacity: The maximum heat input rate to the gas turbine shall not exceed 1998 mmBTU per hour while producing approximately 185 MW based on a compressor inlet air temperature of 32° F, the higher heating value (HHV) of natural gas, and 100% load. The maximum heat input rate to the gas turbine shall not exceed 1827 mmBTU per hour while producing approximately 166 MW based on a compressor inlet air temperature of 32° F, the higher heating value (HHV) of distillate oil, 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.]

8. Authorized Fuel: The gas turbine shall fire only pipeline-quality natural gas with a maximum of 2 grains of sulfur per 100 standard cubic feet of natural gas. As a backup fuel, the gas turbine may fire a limited amount of No. 2 (or a superior grade) distillate oil containing no more than 0.05% sulfur by weight. [Applicant Request; Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

9. Restricted Operation: The gas turbine shall operate only in the combined cycle mode with full emissions control by the SCR and catalytic oxidation systems. The gas turbine shall fire no more than 13,122,000 gallons of distillate oil during any consecutive 12 months (equivalent to 1000 hours per year of full load operation at an inlet temperature of 59° F). When firing natural gas, operation below 50% load is prohibited, excluding startups and shutdowns. When firing natural gas and operating between 50% and 75% of base load, the gas turbine shall not operate more than 2000 hours during any consecutive 12 months. When firing distillate oil, operation below 75% load is prohibited, excluding startups and shutdowns. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

10. Alternate Method of Operation: The combined cycle unit may operate with duct firing in the heat recovery steam generator. Only pipeline quality natural gas shall be fired in the duct burner. The maximum heat input rate to the duct burner shall not exceed 384 mmBTU per hour. [Design; Applicant Request; Rule 62-212.400 (BACT), F.A.C.]

11. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combined cycle gas turbine 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.]

EMISSIONS STANDARDS

{Permitting Note: Appendix BD provides a summary of the BACT determinations specified in this permit.}

12. Emission Standards – Gas Turbine and Fired HRSG: Emissions from the boiler shall not exceed the following limits for carbon monoxide (CO), nitrogen oxides (NOx), opacity, particulate matter (PM), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). The limits apply to the exhaust from the heat recovery steam generator with and without duct firing. Mass emission limits are based a compressor inlet air temperature of 32° F. These limits are specified as representing the Best Available Control Technology in accordance with Rule 62-212.400 (BACT), F.A.C.

Pollutant	Fuel	Load	lb/hour	Emissions Standard
Ammonia [a]	All	All	NA	≤ 5 ppm corrected to 15% oxygen based on a 3-hour test average
CO [b]	Gas	≥ 75%	14.4	≤ 3.5 ppmvd corrected to 15% oxygen based on 24-hour CEMS average
		50-75%	18.9	≤ 10.0 ppmvd corrected to 15% oxygen based on 24-hour CEMS average
	Oil	≥ 75%	31.8	≤ 8.0 ppmvd corrected to 15% oxygen based on 24-hour CEMS average
NOx [c]	Gas	≥ 50%	23.0	≤ 3.5 ppmvd corrected to 15% oxygen based on 3-hour CEMS average
	Oil	≥ 75%	65.0	≤ 10.0 ppmvd corrected to 15% oxygen based on 3-hour CEMS average
Opacity [d]	Gas	≥ 50%	NA	≤ 10% opacity based on a 6-minute average
	Oil	≥ 75%	NA	
PM/PM_{10} [e]	Gas	≥ 50%	17.0	Pipeline natural gas with no more than 2 grains of sulfur per 100 SCF
	Oil	≥ 75%	42.5	Distillate oil with no more than 0.05% sulfur by weight
SAM [f]	Gas	≥ 50%	NA	Pipeline natural gas with no more than 2 grains of sulfur per 100 SCF
	Oil	≥ 75%	NA	Distillate oil with no more than 0.05% sulfur by weight
SO_2 [f]	Gas	≥ 50%	NA	Pipeline natural gas with no more than 2 grains of sulfur per 100 SCF
	Oil	≥ 75%	NA	Distillate oil with no more than 0.05% sulfur by weight
VOC [g]	Gas	≥ 75%	4.4	≤ 2.2 ppmvd corrected to 15% oxygen based on 3-hour test average
		50-75%	17.2	≤ 16.0 ppmvd corrected to 15% oxygen based on 3-hour test average
	Oil	≥ 75%	22.2	≤ 10.0 ppmvd corrected to 15% oxygen based on 3-hour test average

a. Compliance with the ammonia slip limit shall be determined by EPA Method CTM-027.

b. Compliance with the CO limits shall be determined by EPA Method 10 and CEMS certified in accordance with Performance Specification No. 4. For operation at both load conditions in a 24-hour block, the emissions standard shall be prorated according to the number of hours operated at each load.

c. Compliance with the NOx limits shall be determined by EPA Method 7E and CEMS certified in accordance with the acid rain provisions. The compliance period is a 3-hour rolling average.

d. Compliance with the opacity limit shall be determined by EPA Method 9.

e. Compliance with the particulate matter emissions shall be determined by EPA Method 5.

f. Compliance with the fuel specifications shall be demonstrated by keeping the required fuel records. Limits on fuel sulfur effectively limit potential SAM/SO_2 emissions. No testing is required.

g. Compliance with the VOC limits shall be determined by EPA Method 25A. Optionally, EPA Method 18 may be conducted concurrently to deduct emissions of ethane and methane.

13. Emissions Standards – Duct Burner Alone: NOx emissions (expressed as NO_2) shall not exceed 1.6 pounds per megawatt-hour gross energy output based on a 30-day rolling average, as determined by the requirements of the New Source Performance Standards in Subpart Da of 40 CFR 60 and summarized in Appendix Da of this permit. Based on the allowable maximum heat inputs, compliance with the particulate emissions standards in Condition No. 12 shall demonstrate compliance with the NSPS Subpart Da standards of 0.03 lb/mmBTU. [40 CFR 60.44a]

EXCESS EMISSIONS

14. 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 emissions shall be included in any compliance demonstration based on continuous monitoring data. [Rule 62-210.700(4), F.A.C.]

15. Excess Emissions - Defined: The following permit conditions allow excess emissions or the exclusion of monitoring data for during specifically defined periods of startup, shutdown, and malfunction of the combined cycle gas turbine. These conditions apply only if operators employ the best operational practices to minimize the amount and duration of excess emissions during such episodes.

a. *Visible Emissions*: For startups and shutdowns in a calendar day, visible emissions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods, which shall not exceed 20% opacity.

b. *CO and NOx CEMS Data Exclusion*: No more than two hourly average emission rate values shall be excluded from the continuous compliance demonstrations due to warm startups, shutdowns, or unavoidable malfunctions. No more than four hourly average emission rate values shall be excluded from the continuous compliance demonstrations due to cold startups. No more than a total of four hourly average emission rate values shall be excluded from the continuous compliance demonstrations for all such episodes in any calendar day. A "warm startup" is defined as startup after the gas turbine has been shutdown for less than 48 hours. A "cold startup" is defined as startup after the gas turbine has been shutdown for 48 hours or more. An "unavoidable malfunction" is a malfunction beyond the control of the operator, which is documented within 24 hours of occurrence by contacting each Compliance Authority by telephone or facsimile transmittal.

[Design; Rules 62-4.070(3), 62-4.130, 62-210.700, and 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

16. CEMS: The permittee shall install, calibrate, operate and maintain continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests and shall be used to demonstrate continuous compliance with the corresponding CO and NOx emissions standards specified in this section. [Rule 62-212.400 (BACT), F.A.C.]

    a. *CO Monitors.* The CO monitoring system shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4. 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 quarterly to each Compliance Authority. The required CO monitor RATA tests shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The EPA Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall have a dual range capability with maximum spans of 10 and 30 ppmvd corrected to 15% oxygen. Compliance with the CEMS emission standards for CO shall be based on a 24-hour block average starting at midnight of each operating day. The 24-hour block average 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.

    b. *NOx Monitors.* Each NOx monitor shall be certified pursuant to 40 CFR Part 75 and shall be operated and maintained in accordance with the applicable requirements of Subparts B and C in 40 CFR Part 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR Part 75. The required NOx monitor RATA tests shall be performed using EPA Method 7E in Appendix A of 40 CFR 60. The NOx monitor shall have a dual range capability with maximum spans of 10 and 30 ppmvd corrected to 15% oxygen. Compliance with the CEMS emissions standards shall be based on a rolling 3-hour average. For purposes of determining compliance with the CEMS emission standards, missing or excluded data shall not be substituted. Instead, the next valid hourly emission rate value (within the same period of operation) shall be used to complete the 3-hour rolling average.

    c. *O_2 or CO_2 Monitors.* The oxygen (O_2) content or carbon dioxide (CO_2) content of the flue gas shall also be monitored at the location where CO and NOx 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 by the CEMS using F-factors that are appropriate for each fuel fired. Each O_2 and CO_2 monitor shall be certified pursuant to Performance Specification No. 3 in Appendix B of 40 CFR 60. Quality assurance procedures shall conform to the requirements in Appendix F of 40 CFR 60. The required "Data Assessment Report of Section 7" of Appendix F shall be made each calendar quarter and reported quarterly to each Compliance Authority. The required O_2 or CO_2 monitor RATA tests shall be performed using EPA Method 3B in Appendix A of 40 CFR 60.

    d. *Data Collection.* Each hourly 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). The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly averages. 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 CEMS 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 CEM emission standards for CO and NOx as specified in this permit. 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. *Data Exclusion.* All required emissions data shall be recorded by the CEMS during episodes of startup, shutdown and malfunction. CO and NOx emissions data recorded during such episodes may be excluded from the corresponding compliance-averaging period subject to the conditions specified in Condition No. 15 of this section. All periods of data excluded for any startup, shutdown or malfunction episode shall be consecutive for each episode. The permittee shall minimize the duration of data excluded for startup, shutdown and malfunctions, to the extent practicable. Data recorded during startup, shutdown or malfunction events shall not be excluded if the startup, shutdown or malfunction 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 episodes of startup, shutdown and malfunction. 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.

f. *Data Exclusion and Excess Emissions Reports.* A summary report of the duration of data excluded from each compliance average calculation, and all instances of missing data from monitor downtime, shall be reported quarterly to each Compliance Authority. This report shall be consolidated with the report required pursuant to 40 CFR 60.7. For purposes of reporting "excess emissions" pursuant to the requirements of 40 CFR 60.7, excess emissions shall be defined to include the hourly emissions which are recorded by the CEMS during periods of data excluded for episodes of startup, shutdown and malfunction, as allowed above. The duration of excess emissions shall include the duration of the periods of data excluded for such episodes. Reports required by this paragraph and by 40 CFR 60.7 shall be submitted no less than quarterly, including periods in which no data is excluded or no instances of missing data occur.

g. *Notification*: If a CEMS reports CO or NOx emissions in excess of an emissions standard, the permittee shall notify each Compliance Authority within one working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

h. *Availability.* Monitor availability for CO and NOx CEMS shall be 95% or greater in any calendar quarter. The report required in Appendix XS of this permit 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.

{Permitting Note: Compliance with these requirements will ensure compliance with the other applicable CEMS requirements such as: NSPS Subpart 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; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}

[Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

17. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEMS with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load. [Rules 62-4.070(3) and 62-212.400 (BACT), F.A.C.]

EMISSIONS PERFORMANCE TESTING

{Permitting Note: See Appendix SC for standard conditions regarding emissions testing.}

18. Test Methods: 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.}
5	Determination of Particulate Matter Emissions from Stationary Sources {Note: For gas firing, the minimum sampling time shall be two hours per run and the minimum sampling volume shall be 60 dscf per run.}
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. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
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

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A:C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C. [Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

19. Initial Compliance Tests: The combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for CO, NOx, PM, visible emissions and ammonia slip. The tests shall be conducted within 60 days after achieving at least 90% of the maximum permitted capacity, but not later

than 180 days after initial operation of the combined cycle gas turbine. The certified CEMS data may be used to demonstrate initial compliance with the CO and NOx standards. Emissions shall be reported in units of the standards (lb/hour and ppmvd corrected to 15% oxygen, where applicable). Mass emissions may be determined with measured flow rates or by using appropriate F-factors for each fuel. In addition, NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run in terms of "ppmvd corrected to 15% oxygen". [Rule 62-297.310(7)(a)1, F.A.C.]

20. Continuous Compliance – Gas Turbine: The required CEMS shall be used to continuously demonstrate compliance with the CO and NOx emissions standards. For PM and VOC emissions, compliance with the CO and opacity standards shall serve as indicators of good combustion. Record keeping shall be used to demonstrate compliance with the fuel sulfur specifications. [Rule 62-212.400 (BACT), F.A.C.]

21. Continuous Compliance – Duct Burner: The NOx CEMS system shall also be used to determine NOx emissions expressed as pounds of NO_2 per megawatt-hour gross energy output based on 30-day rolling average to demonstrate continuous compliance with the duct burner emissions standard of 40 CFR 60.44a. See Appendix Da of this permit. [40 CFR 60.44a]

22. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), the combined cycle gas turbine shall be tested to demonstrate compliance with the emission standards for ammonia slip and visible emissions. CO and NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run in terms of "ppmvd corrected to 15% oxygen". The annual test report shall also indicate the date the required CO and NOx RATA tests were performed and summarize the results. If no more than 400 hours of distillate oil firing occurs during the federal fiscal year, compliance tests for ammonia slip and visible emissions when firing distillate oil are not required. Pursuant to Rule 62-297.310(7)(b), F.A.C., the Department may require additional testing if it believes that a standard is being exceeded. {Permitting Note: Continuous compliance with the CO and NOx standards is demonstrated with certified CEMS system data.} [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

23. Alternate Sampling Requirements: Due to the unique site conditions of this project, the following requirements are specified for sampling locations and exhaust flow measurements. The four required test ports shall be located at least 5 feet below the stack outlet with each pair in a line offset 45 degrees from the axis of the internal rain gutter. The CEMS probe(s) shall also be located at least 5 feet below the stack outlet and positioned so that the probe inlet(s) are not located over the gutter or other obstruction associated with the weather damper. Stack exhaust flows shall be determined by fuel flow and appropriate F-factors for each fuel rather than direct gas flow measurement. [Rules 62-4.070(3) and 62-210.400 (BACT), F.A.C.]

RECORDS

24. Fuel Sulfur Records: Compliance with the fuel sulfur specification for natural gas shall be demonstrated by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis 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) in conjunction with the provisions of 40 CFR 75 Appendix D. Compliance with the distillate oil sulfur limit shall be demonstrated by taking an initial sample, analyzing the sample for fuel sulfur, and reporting the results with the initial emissions compliance test report. Sampling and analyzing 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 distillate oil delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from

the vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content. [Rules 62-4.070(3) and 62-210.400 (BACT), F.A.C.]

25. Monitoring of Operations: To demonstrate compliance with the fuel consumption limits, the permittee shall monitor and record the rates of fuel consumption for the gas turbine and duct burner in accordance with the provisions of 40 CFR 75 Appendix D. To demonstrate compliance with the turbine capacity requirements, the permittee shall monitor and record the operating rate of the gas turbine 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 CEMS 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.]

26. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following information: hours of gas turbine operation on each fuel; the hours of operation between 50% and 100% of base load when firing natural gas; the total heat input to the gas turbine for each fuel (mmBTU); the gallons of distillate oil fired; and the total heat input to the duct burner (mmBTU). The information shall be recorded in a written (or electronic log) and shall summarize these operating parameters for the previous month as well as the previous 12 months. 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. [Rule 62-4.070(3), F.A.C.]

REPORTS

27. Quarterly Excess Emissions Reports: Following the NSPS format provided in Appendix XS of this permit, emissions shall be reported as "excess emissions" when emission levels exceed the standards specified in this permit (including periods of startup, shutdown and malfunction). Within 30 days following each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of excess emissions, periods of data exclusion, and CEMS systems monitor availability for the previous calendar quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

OTHER REQUIREMENTS

28. Applicable Requirements: Section 4 of the permit includes the following additional applicable requirements for the combined cycle unit: 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; and Appendix XS - Continuous Monitor Systems Quarterly Report. [40 CFR 60 Subparts Da and GG; Chapters 62-4, 62-2120, 62-296, and 62-297]

SECTION 4. APPENDICES

Contents

Final BACT Determinations and Emissions Standards

The following tables summarize the final Best Available Control Technology determinations for this project and the corresponding emissions standards. [Rules 62-212.400(BACT) and 62-4.070(3), F.A.C.]

Table B-1. EU-001, Combined Cycle Gas Turbine No. CC-1 Firing Natural Gas

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: Natural gas with a maximum of 2.0 grains of sulfur per 100 SCF	Monthly vendor analysis (ASTM Methods D4084-82 or D3246-81)
Ammonia	*Ammonia Slip*: 5 ppmvd @ 15% oxygen	Initial and annual tests by EPA Method CTM-027
CO	*BACT Control*: Catalytic oxidation system	Continuous compliance demonstration
	BACT Standards ≥ 75% Load: 3.5 ppmvd @ 15% oxygen based on 24-hour CEMS avg. 50-75% Load: 10.0 ppmvd @ 15% oxygen based on 24-hour CEMS avg.	 Certified CEM system data Certified CEM system data
NOx	*BACT Control*: Selective catalytic reduction with dry low-NOx combustion design	Continuous compliance demonstration
	BACT Standard: 3.5 ppmvd @ 15% O_2, 3-hour CEMS avg.	Certified CEM system data
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels with good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: 17.0 lb/hour	Initial test; EPA Method 5 (front-half catch only)
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	Initial and annual tests; EPA Method 9
SAM/SO_2	*BACT Control*: Fuel sulfur specifications	Vendor analysis (ASTM Methods D4084-82 or D3246-81)
	BACT Standard: Potential SAM/SO_2 emissions are effectively limited by the fuel specifications.	Monthly records
VOC	*BACT Control*: Catalytic oxidation system	Initial tests; compliance with fuel specifications and CO standards
	BACT Standards ≥ 75% Load: 2.2 ppmvd @ 15% oxygen based on a 3-hour test avg. 50-75% Load: 16.0 ppmvd @ 15% oxygen based on a 3-hour test avg.	 Initial test; EPA Methods 18 and 25A Initial test; EPA Methods 18 and 25A

Note: The BACT limits apply to the exhaust from the heat recovery steam generator after the control devices with, and without, duct firing. Except for startup and shutdown, operation below 50% load when firing natural gas is prohibited.

Table B-2. EU-001, Combined Cycle Gas Turbine No. CC-1 Firing Distillate Oil

Parameter	Controls and Emissions Standards	Compliance Method
Fuel	*Specification*: Distillate oil with a maximum of 2.0 grains of sulfur per 100 SCF	Monthly vendor analysis (ASTM Methods D4084-82 or D3246-81)
Ammonia	*Ammonia Slip*: 5 ppmvd @ 15% oxygen	Initial and annual tests by EPA Method CTM-027
CO	*BACT Control*: Catalytic oxidation system	Continuous compliance demonstration
	BACT Standard: 8.0 ppmvd @ 15% oxygen based on a 24-hour CEMS avg.	Certified CEM system data
NOx	*BACT Control*: Selective catalytic reduction with wet injection	Continuous compliance demonstration
	BACT Standard: 10.0 ppmvd @ 15% O_2, 3-hour CEMS avg.	Certified CEM system data
PM/PM_{10}	*BACT Control*: Efficient combustion of clean fuels with good operating practices	Compliance with fuel specifications and CO standards
	BACT Standard: 42.5 lb/hour	Initial test; EPA Method 5 (front-half catch only)
	BACT Standard: Visible emissions ≤ 10% opacity, 6-minute avg.	Initial and annual tests; EPA Method 9
SAM/SO_2	*BACT Control*: Fuel sulfur specifications	Vendor analysis (ASTM Methods D4084-82 or D3246-81)
	BACT Standard: Potential SAM/SO_2 emissions are effectively limited by the fuel specifications.	Monthly records
VOC	*BACT Control*: Catalytic oxidation system	Initial tests; compliance with fuel specifications and CO standards
	BACT Standard: 10.0 ppmvd @ 15% oxygen based on a 3-hour test avg.	Initial test; EPA Methods 18 and 25A

Notes: The BACT limits apply to the exhaust from the heat recovery steam generator after the control devices with, and without, duct firing. Except for startup and shutdown, operation below 75% load when firing distillate oil is prohibited. If distillate is fired for no more than 400 hours during the federal fiscal year, compliance tests for ammonia slip and visible emissions are not required.

FINAL BACT DETERMINATIONS

As summarized in the previous tables, the Department determines that the standards specified in this permit represent the Best Available Control Technology (BACT) for emissions of carbon monoxide, particulate matter, nitrogen oxides, sulfuric acid mist, sulfur dioxide, and volatile organic compounds from the combined cycle gas turbine. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination, which was issued concurrently with the draft permit.

Determination By:

(DRAFT)

J. F. Koerner, P.E., Project Engineer (Date)
New Source Review Section

Recommended By:

(DRAFT)

C. H. Fancy, Chief (Date)
Bureau of Air Regulation

Approved By:

(DRAFT)

Howard L. Rhodes, Director (Date)
Division of Air Resources Management

SECTION 4. APPENDIX CF

Citation Format

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 CRF 60.7]

Means: Title 40, Part 60, Section 7

NSPS Subpart Da Requirements for Duct Burners

The following emissions unit is subject to the applicable requirements of Subpart A (General Provisions) and Subpart Da (Duct Burner) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C.

ID	Emission Unit Description
001	**Combined Cycle Unit No. CC-1** consists of Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set (180 MW), a fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air cooling, and other associated equipment.

NSPS GENERAL PROVISIONS

{Permitting Note: The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.}

§ 60.40a Applicability and Designation of Affected Facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

§ 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.

§ 60.42a Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain particulate matter in excess of:

(1) 13 ng/J (0.03 lb/million Btu) heat input derived from the combustion of solid, liquid, or gaseous fuel;

(2) 1 percent of the potential combustion concentration (99 percent reduction) when combusting solid fuel; and

(3) 30 percent of potential combustion concentration (70 percent reduction) when combusting liquid fuel.

(b) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

§ 60.44a Standard for nitrogen oxides.

(d) (1) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no new source owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction commenced after July 9, 1997 any gases which contain nitrogen oxides (expressed as NO_2) in excess of 1.6 pounds per megawatt-hour gross energy output, based on a 30-day rolling average, except as provided under § 60.46a(k)(1).

§ 60.45a Commercial demonstration permit. (Not Applicable)

§ 60.46a Compliance provisions.

(i) *Compliance provisions for sources subject to § 60.44a(d)(1).* The owner or operator of an affected facility subject to § 60.44a(d)(1) (new source constructed after July 7, 1997) shall calculate NOx emissions by multiplying the average hourly NOx output concentration, measured according to the provisions of § 60.47a(c), by the average hourly flow rate, measured according to the provisions of § 60.47a(l), and divided by the average hourly gross energy output, measured according to the provisions of § 60.47a(k).

(k) *Compliance provisions for duct burners subject to § 60.44a(d)(1).* To determine compliance with the emissions limits for NOx required by § 60.44a(d)(1) for duct burners used in combined cycle systems, either of the procedures described in paragraphs (k)(1) and (2) of this section may be used:

(2) The owner or operator of an affected duct burner used in a combined cycle system may elect to determine compliance with the NOx standard in § 60.44a(d)(1) on a 30-day rolling average basis as indicated in paragraphs (k)(2)(i) through (iv) of this section.

(i) The emission rate (E) of NOx shall be computed using Equation 2 of this section:

$$E = (Csg \quad Qsd) / Occ \qquad \text{(Eq. 2)}$$

Where:

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

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

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

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

(ii) The continuous emissions monitoring system specified under § 60.47a for measuring NOx and oxygen shall be used to determine the average hourly NOx concentrations (Csg). The continuous flow monitoring system specified in § 60.47a(l) shall be used to determine the volumetric flow rate (Qsg) of the exhaust gas. The sampling site shall be located at the outlet from the steam generating unit. Data from a continuous flow monitoring system certified (or recertified) following procedures specified in 40 CFR 75.20, meeting the quality assurance and quality control requirements of 40 CFR 75.21, and validated according to 40 CFR 75.23 may be used.

(iii) The continuous monitoring system specified under § 60.47a(k) for measuring and determining gross energy output shall be used to determine the average hourly gross energy output from the entire combined cycle unit (Occ), which is the combined output from the combustion turbine and the steam generating unit.

(iv) The owner or operator may, in lieu of installing, operating, and recording data from the continuous flow monitoring system specified in § 60.47a(l), determine the mass rate (lb/hr) of NOx emissions by installing, operating, and maintaining continuous fuel flow meters following the appropriate measurements procedures specified in appendix D of 40 CFR part 75. If this compliance option is selected, the emission rate (E) of NOx shall be computed using Equation 3 of this section:

$$E = (Ersg \quad Hcc) / Occ \qquad \text{(Eq. 3)}$$

Where:

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

Ersg = average hourly emission rate of NOx exiting the steam generating unit heat input calculated using appropriate F-factor as described in Method 19, ng/J (lb/million Btu)

Hcc = average hourly heat input rate of entire combined cycle unit, J/hr (million Btu/hr)

Occ = average hourly gross energy output from entire combined cycle unit, J (Mwh)

NSPS Subpart Da Requirements for Duct Burners

{Selected by the permittee.}

§ 60.47a Emission monitoring.

(k) The procedures specified in paragraphs (k)(1) through (3) of this section shall be used to determine gross output for sources demonstrating compliance with the output-based standard under § 60.44a(d)(1).

(1) The owner or operator of an affected facility with electricity generation shall install, calibrate, maintain, and operate a wattmeter; measure gross electrical output in megawatt-hour on a continuous basis; and record the output of the monitor.

(2) The owner or operator of an affected facility with process steam generation shall install, calibrate, maintain, and operate meters for steam flow, temperature, and pressure; measure gross process steam output in joules per hour (or Btu per hour) on a continuous basis; and record the output of the monitor.

(3) For affected facilities generating process steam in combination with electrical generation, the gross energy output is determined from the gross electrical output measured in accordance with paragraph (k)(1) of this section plus 50 percent of the gross thermal output of the process steam measured in accordance with paragraph (k)(2) of this section.

(n) Gas-fired and oil-fired units. The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in 40 CFR 72.2, may use, as an alternative to the requirements specified in either paragraph (l) or (m) of this section, a fuel flow monitoring system certified and operated according to the requirements of appendix D of 40 CFR part 75.

{Selected by the permittee.}

§ 60.48a Compliance Determination Procedures and Methods.

These requirements are applicable to all Subpart Da. Please refer to the CFR.

§ 60.49a Reporting Requirements.

These requirements are applicable to all Subpart Da. Please refer to the CFR.

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 extend 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); and
    c. 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.

NSPS Subpart GG Requirements for Gas Turbines

The following emissions units are subject to the applicable requirements of Subpart A (General Provisions) and Subpart GG (Stationary Gas Turbines) established as New Source Performance Standards in 40 CFR 60 and adopted by reference in Rule 62-204.800(7)(b), F.A.C.

ID	Emission Unit Description
001	**Combined Cycle Unit No. CC-1** consists of Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set (180 MW), a fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air cooling, and other associated equipment.

NSPS GENERAL PROVISIONS

{Permitting Note: The emissions units are subject to the applicable General Provisions of the New Source Performance Standards including 40 CFR 60.7 (Notification and Record Keeping), 40 CFR 60.8 (Performance Tests), 40 CFR 60.11 (Compliance with Standards and Maintenance Requirements), 40 CFR 60.12 (Circumvention), 40 CFR 60.13 (Monitoring Requirements), and 40 CFR 60.19 (General Notification and Reporting Requirements). The General Provisions are not included in this permit, but can be obtained from the Department upon request.}

NSPS SUBPART GG REQUIREMENTS

{Permitting Note: Each gas turbine shall comply with all applicable requirements of 40 CFR 60, Subpart GG adopted by reference in Rule 62-204.800(7)(b), F.A.C. Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in ***bold*** *immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.}*

§ 40 CFR 60.332 Standard for Nitrogen Oxides.

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

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

where:

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

Y = manufacturer's rated heat rate 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 = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent by volume)
$N \le 0.015$	0
$0.015 < N \le 0.1$	0.04(N)
$0.1 < N \le 0.25$	0.004+0.0067(N–0.1)
$N > 0.25$	0.005

Where, N = the nitrogen content of the fuel (percent by weight).

<u>Department requirement</u>: When firing natural gas, the "F" value shall be assumed to be 0.

{Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the manufacturer are approximately 10.0/10.6 for natural gas/distillate oil. The equivalent emission standards are approximately 108/102 ppmvd corrected to 15% oxygen. The emissions standards in Section 3 of this permit are more stringent than this requirement.}

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

§ 40 CFR 60.333 Standard for Sulfur Dioxide.

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.

§ 40 CFR 60.334 Monitoring of Operations.

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: **The requirement to monitor the nitrogen content of pipeline quality natural gas fired is waived. A NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the permittee shall obtain a monthly vendor analysis indicating the sulfur content of the natural gas being supplied from the pipeline for each month of operation.**

{Note: This is consistent with the custom fuel monitoring policy and guidance from EPA Region 4.}

(c) For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: **The continuous compliance demonstration by NOx CEM system data shall substitute for the requirements of paragraph (c)(1). NOx CEM system data shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.**

{Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEM systems specified by the specific conditions of this permit satisfy these requirements.}

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

§ 40 CFR 60.335 Test Methods and Procedures.

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed 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.

Department requirement: The permittee is not required to have the NOx monitor continuously correct NOx emissions concentrations to ISO conditions. However, the permittee shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

{Note: This is consistent with guidance from EPA Region 4.}

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The permittee is allowed to conduct initial performance tests at a single load because the permit requires demonstration of continuous compliance with the NOx BACT standards.

{Note: This is consistent with guidance from EPA Region 4.}

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The permittee is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system 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 NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above. Flow rate data shall be obtained to calculate mass emission rates.

{Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.}

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

Department requirement: **The permit specifies sulfur testing methods and allows the permittee to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content.**

{Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.}

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

{Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.}

Standard Conditions

{Permitting Note: 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 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.]

4. 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.]

5. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. [Rule 62-296.320(2), F.A.C.]

6. 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.]

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

TESTING REQUIREMENTS

8. 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.]

9. 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.]

10. 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.]

11. 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.]

12. Sampling Facilities: The permittee shall provide stack testing facilities and sampling locations in accordance with Rule 62-297.310(6), F.A.C.

13. Test Notification: The permittee shall notify the Compliance Authority in writing at least 30 days prior to any initial NSPS performance tests and at least 15 days prior to any other required tests. [Rule 62-297.310(7)(a)9, F.A.C. and 40 CFR 60.7, 60.8]

14. 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.]

RECORDS AND REPORTS

15. 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.]

16. 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.]

17. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to each Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.].

Continuous Monitor Systems Quarterly Report

{Note: This form is referenced in 40 CFR 60.7, Subpart A, General Provisions.}

Pollutant *(Circle One)*: Nitrogen Oxides (NOx) Carbon Monoxide (CO)

Reporting period dates: From ____________________ to ____________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer and Model No.: ____

Date of Latest CMS Certification or Audit: ______________________________

Process Unit(s) Description: ____

Total source operating time in reporting period [a]: ______________________________

Emission data summary [a]		CMS performance summary [a]	
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] [b]		3. [Total CMS Downtime] x (100%) / [Total source operating time]	

[a] For opacity, record all times in minutes. For gases, record all times in hours.

[b] 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 to CMS, process or controls during last 6 months.

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

____
Name

____
Title

____ ____________________
Signature *Date*

Memorandum

Florida Department of Environmental Protection

TO: Clair Fancy, Chief, BAR

THROUGH: Al Linero, Administrator - New Source Review Section

FROM: Jeff Koerner, New Source Review Section

DATE: June 18, 2001

SUBJECT: Project No. 1110102-001-AC (PSD-FL-320)
ENRON – Fort Pierce Re-Powering Project, LLC
New 180 MW Combined Cycle Gas Turbine
(New plant to be located adjacent to existing H. D. King Plant in Fort Pierce.)

Attached for your review are the following items:

- Intent to Issue Permit and Public Notice Package;
- Technical Evaluation and Preliminary Determination;
- Draft Permit; and
- PE Certification

The Technical Evaluation and Preliminary Determination provides a detailed description of the project rule applicability, and BACT determinations. The P.E. certification briefly summarizes proposed project and BACT determinations. Day #74 is July 28, 2001. I recommend your approval of the attached Draft Permit for this project.

CHF/AAL/jfk

Attachments

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

P.E. CERTIFICATION STATEMENT

PERMITTEE

Fort Pierce Re-Powering Project, LLC
1311 North Indian River Drive
Fort Pierce, FL 34950-4425

Authorized Representative:
Ben Jacoby, Attorney-In-Fact

Project No. 1110102-001-AC
Draft Permit No. PSD-FL-320
Facility ID No. 1110102
SIC No. 4911

PROJECT DESCRIPTION

The applicant proposes to construct a new 180 MW combined cycle gas turbine plant (Fort Pierce Re-Powering Project, LLC) to be located adjacent to the existing H. D. King Electric Generating Plant at 1311 North Indian River Drive in Fort Pierce, St. Lucie County, Florida. The new plant will consist of a Mitsubishi Heavy Industries Model 501F gas turbine-electrical generator set (180 MW), a fired heat recovery steam generator, a selective catalytic reduction system, a catalytic oxidation system, inlet air-cooling, and other associated equipment. The primary fuel is pipeline-quality natural gas with up to 1000 hours of distillate oil firing as a backup fuel. Emissions from the project exceed the PSD Significant Emission Rates for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2), and volatile organic compounds (VOC). In addition, NSPS Subpart Db applies to the duct burner and NSPS Subpart GG applies to the gas turbine.

- For emissions of PM/PM_{10}, SAM, and SO_2, the draft BACT was based on the efficient combustion of low sulfur fuels.
- For CO and VOC emissions, the draft BACT was based on an oxidation catalyst. (Due to elevated CO and VOC emission levels, operation between 50% and 75% of base load when firing natural gas is limited to 2000 hours per year. When firing distillate oil, operation below 75% of base load is prohibited.)
- When firing natural gas, the draft BACT for NOx emissions was determined to be dry low-NOx combustion technology combined with Selective Catalytic Reduction (≤ 3.5 ppmvd @ 15% oxygen, 3-hour average). When firing distillate oil, the draft BACT for NOx emissions was determined to be wet injection combined with Selective Catalytic Reduction (≤ 10.0 ppmvd @ 15% oxygen, 3-hour average). Ammonia slip is limited to 5 ppm.

The BACT determinations include emissions from the gas turbine and HRSG with duct firing. Initial tests are required for emissions of CO, NOx, PM, visible emissions, VOC and ammonia slip. Record keeping of the fuel sulfur content is required for SAM and SO_2 emissions. CEMS are required for CO and NOx emissions. The NOx CEMS must also show continuous compliance with NSPS Subpart Da standard for duct burners. After the initial tests, compliance with the fuel specifications and CO standards shall serve as indicators of efficient combustion for emissions of PM and VOC. The specified technologies utilize clean fuels and are consistent with recent determinations in Florida and other states.

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).*

Jeffery J. Koerner — 6-18-01

Jeffery F. Koerner, P.E.
Registration Number: 49441

(Date)