Memorandum

Florida Department of
Environmental Protection

TO: Trina L. Vielhauer

THRU: A.A. Linero

FROM: Cindy Mulkey

DATE: October 25, 2005

SUBJECT: FMPA Treasure Coast Energy Center
300 MW Combined Cycle Plant
DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

Attached is the public notice package for construction of a 300 MW Combined Cycle Plant at the Treasure Coast Energy Center in St. Lucie County.

The basic unit is a nominal 170-megawatt General Electric 7FA gas and oil-fired combustion turbine-generator. The project includes a duct fired HRSG that will raise sufficient steam to produce another 130 MW via a steam-driven electrical generator. A selective catalytic reduction system including ammonia storage is included.

A 990,000 gallon storage tank will be constructed for the back-up ultra low sulfur fuel oil that will be used for no more than 500 hours per year.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by SCR to 2 ppmvd (gas) and 8 ppmvd (oil). The ammonia limit is proposed at 5 ppmvd by agreement with the applicant. This will reduce formation of ammoniated particulate species.

Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas, limited fuel oil use and the design of the GE unit.

The project was deemed complete on August 28th upon receipt of FMPA's response to Power Plant Siting's Statement of Insufficiency. The proposed issue date of October 28 is Day 60.
I recommend your signature and approval of this Intent to Issue.

AAL/cm

Attachments

Department of
Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

October 28, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger A. Fontes, General Manager and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Re: Treasure Coast Energy Center
Combined Cycle Power Project
DEP File No. 1110121-001-AC (PSD-FL-353, PA 05-48)

Dear Mr. Fontes:

Enclosed are documents indicating the Department's intent to issue an air construction permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to the Florida Municipal Power Agency for construction of a 300 megawatt combined cycle unit and associated support facilities at the proposed Treasure Coast Energy Center. The documents include: the "Intent to Issue Air Construction Permit;" the "Public Notice of Intent to Issue Air Construction Permit;" the Department's "Technical Evaluation and Preliminary Determination" including a draft determination of Best Available Control Technology; and the Draft Permit.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, Program Administrator, Permitting South Section, at the above letterhead address. If you have any questions, please call Ms. Cindy Mulkey at 850/921-8968 or Ms. Debbie Nelson at 850/921-9537 or Mr. Linero at 850/921-9523.

Sincerely,

Trina L. Vielhauer

Trina L. Vielhauer, Chief,
Bureau of Air Regulation

TLV/cem

Enclosures

In the Matter of an
Application for Permit by:

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative:
Mr. Roger A. Fontes, General Manager and CEO

DEP File No. 1110121-001-AC
Draft Permit No. PSD-FL-353
Siting No. PA 05-48
Treasure Coast Energy Center
300 MW Combined Cycle Unit

INTENT TO ISSUE PSD PERMIT

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

The applicant, Florida Municipal Power Agency, applied on April 14, 2005 (sufficient August 29) to the Department for a PSD permit to construct a nominal 300 megawatt combined cycle combustion turbine project at the proposed Treasure Coast Energy Center near Fort Pierce, St. Lucie County.

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

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

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

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

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice of Intent to Issue PSD Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue PSD Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/28/05 to the persons listed:

Roger Fontes, FMPA*
Susan Schumann, FMPA
Mayor, Fort Pierce
Chair, St. Lucie County BCC
Gregg Worley, U.S. EPA Region 4, Atlanta GA
John Bunyak, National Park Service, Denver CO
Darrel Graziani, DEP SED
Stanley Armbruster, B&V
Hamilton Oven, DEP Siting

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.

(Clerk) 10/28/05 (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1110121-001-AC, PSD-FL-353, and PA 05-48

FMPA Treasure Coast Energy Center
Combined Cycle Power Project

St. Lucie County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD Permit) of Air Quality to Florida Municipal Power Agency. The permit is to construct a nominal 300 megawatt (MW) combined cycle electrical power generating plant at the Treasure Coast Energy Center near Fort Pierce, St. Lucie County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400, Florida Administrative Code (F.A.C.), for emissions of particulate matter (PM/PM_{10}), carbon monoxide (CO), sulfur dioxide (SO_2), sulfuric acid mist, and nitrogen oxides (NO_X). The applicant's name and address are Florida Municipal Power Agency, 8553 Commodity Circle, Orlando, Florida 32819.

The project consists of: a nominal 170 MW General Electric 7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW separate steam-electrical generator, a 170-foot stack, a mechanical draft cooling tower with drift eliminators, a 990,000 gallon fuel oil storage tank, and other ancillary equipment. Back-up ultra low sulfur (ULS) fuel oil (0.0015 percent sulfur) will be burned for a maximum of 500 hours per year.

NO_x emissions will be controlled by selective catalytic reduction (SCR) to achieve 2 parts per million by volume, dry, at 15 percent oxygen (ppmvd) while burning gas and 8 ppmvd while burning ULS fuel oil. Emissions of CO will be controlled to 4.1 and 8 ppmvd while burning gas and fuel oil respectively. Emissions of PM/PM_{10}, SO_2, sulfuric acid mist, volatile organic compounds, and hazardous air pollutants (HAP) will be controlled to very low levels by good combustion and use of inherently clean pipeline quality natural gas and ULS fuel oil. Ammonia emissions (NH_3) generated due to NO_X control will be limited to 5 ppmvd.

FMPA's estimates of maximum potential annual emissions from the project are summarized in the following table.

Pollutants	Maximum Potential Emissions Tons Per Year	PSD Significant Emission Rate Tons Per Year
CO	231	100
NO_x	90	40
PM/PM_{10}	176/171	25/15
Sulfuric Acid Mist	22.4	7
SO_2	56.6	40
VOC	23.4	40
Lead	0.007	0.6
Mercury	0.001	0.1
HAPs	12.5	NA

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the significant impact levels applicable to areas outside of the Everglades National Park and the Chassahowitzka Wilderness Area (i.e. PSD Class II Areas). Therefore, multi-source modeling was not required for ambient air quality standards Class II increments. The project has no significant impact on the PSD Class I Chassahowitzka Wilderness and Everglades National Park areas. Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or contribute to a violation of any state or federal ambient air quality standard.

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

The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. This PSD permitting action is being coordinated with a certification under the Power Plant Siting Act (Sections 403.501-519, F.S.). If a petition for an administrative hearing on the Department's Intent to Issue is filed by a substantially affected person, that hearing shall be consolidated with the certification hearing, as provided under Section 403.507(3). Mediation is not available in this proceeding.

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

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

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

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

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida, 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Southeast District Office
400 North Congress Avenue, Suite 200
West Palm Beach, Florida 334018
Telephone: 561/681-6774
Fax: 561/681-6755

Dept. of Environmental Protection
Southeast District Branch Office
1801 SE Hillmoor Dr., Suite C-204
Port St. Lucie, Florida 34952
Telephone: 772/398-2806
Fax: 772/398-2815

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator, South Permitting Section, Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information. The application, key correspondence, draft permit and technical evaluation can be accessed at www.dep.state.fl.us/Air/permitting/construction/treasurecoast.htm.

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Municipal Power Agency
Treasure Coast Energy Center

300-Megawatt Combined Cycle Power Plant

St. Lucie County

DEP File No. 1110121-001-AC
PSD-FL-353, PA 05-48

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South

October 28, 2005

I. APPLICATION INFORMATION

A. Applicant Name and Address

Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative: Roger A. Fontes, General Manager and CEO

B. Processing Schedule

April 14, 2005: Received Site Certification Application (SCA) including PSD application

June 6, 2005: Sufficiency determination issued by DEP Siting Coordination Office (SCO) – found insufficient.

July 29, 2005: Received Response to SCO sufficiency questions

August 29, 2005: SCO issues determination finding SCA/PSD Application sufficient

October 28, 2005: Intent to Issue PSD Permit distributed

C. Facility Location

Treasure Coast Energy Center (TCED) will be located in St. Lucie County, southwest of the City of Fort Pierce, East of Highway 95, on Selvitz Road. The site is 180 km from the nearest Federal Prevention of Significant Deterioration (PSD) Class I Area, Everglades National Park. The Chassahowitzka Class I area is 260 km to the Northwest. The UTM coordinates for this site are 561.51 km East and 3028.99 km North. The locations of Fort Pierce and TCEC are shown in Figures 1 and 2.

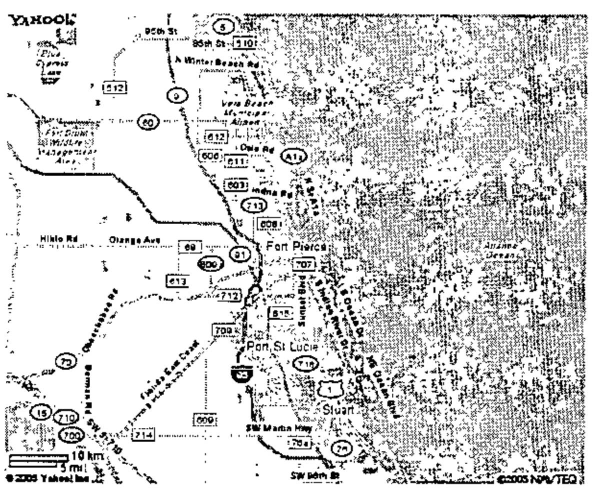


Figure 1. Location of Fort Pierce

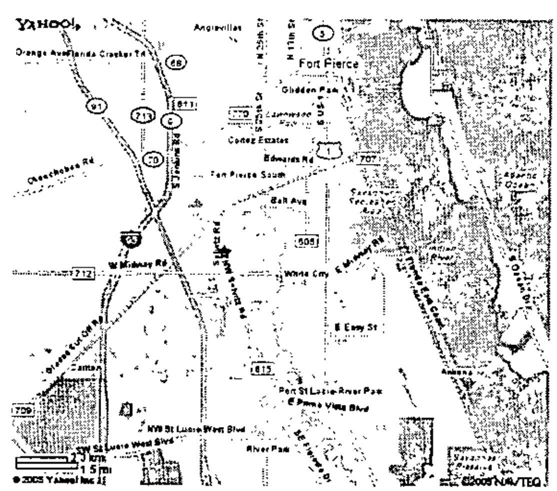


Fig. 2. Location, Treasure Coast Energy Center

D. Standard Industrial Classification Codes (SIC)

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

E. Regulatory Categories

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

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

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

PSD: The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 Prevention of Significant Deterioration (PSD) Major Facility 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., Prevention of Significant Deterioration of Air Quality.

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the unit will be subject to Subpart KKKK, and may no longer be subject to Subparts GG. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a major source of HAPs, therefore Unit 1 is not subject to the provisions of 40 CFR Part 63, Subpart YYYY (CT MACT).

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

II. PROPOSED PROJECT SUMMARY

A. Project Description

The applicant proposes to construct a "one-on-one" (1x1) F-Class combined cycle unit (Unit 1) and associated auxiliary equipment. Unit one will consist of one General Electric PG7241 FA combustion turbine generator(CT), a duct-fired heat recovery steam generator (HRSG), and a steam turbine generator (STG) for an overall nominal rating of 300 MW. The key components of the GE MS 7001 FA (a predecessor of the PG 7241 FA) are identified in Figure 3. An exterior view is also shown. The project includes highly automated controls, described as the GE Mark VI Gas Turbine Control System to fulfill all of the gas turbine control requirements.

Auxiliary equipment includes the following: a 990,000 gallon fuel oil storage tank; a diesel engine driven fire pump with an associated 500 gallon fuel oil storage tank, a safe shutdown generator with an associated 1,000 gallon fuel oil storage tank, a mechanical draft cooling tower equipped with drift eliminators, and a 170-foot exhaust stack.

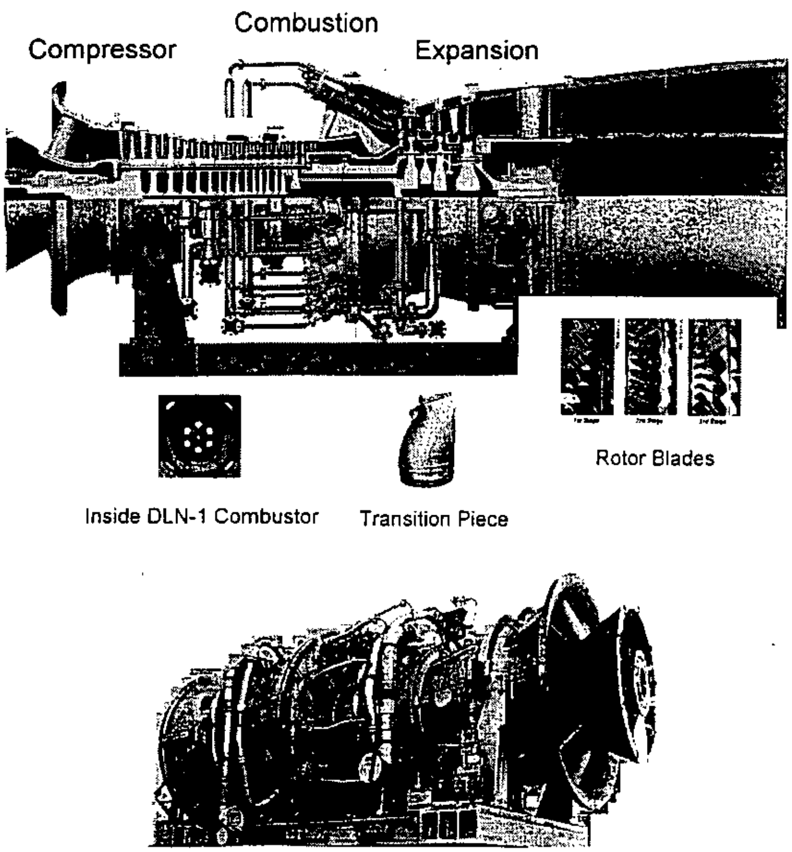


Figure 3 - Internal and External Views of Early GE 7FA

Additional project details, as proposed, are described below.

- Fuel: TCEC will use natural gas as the primary fuel for up to 8760 hours per year, and ultra-low sulfur (ULS) fuel oil (0.0015% Sulfur) as a backup fuel. The applicant requests operation with ULS fuel oil up to 500 hours per year.
- Generating Capacity: The combustion turbine has a nominal generating capacity of 170 MW. The duct-fired HRSG provides steam to the steam turbine electrical generator, which has a nominal capacity of 130 MW. The total nominal generating capacity of the 1 x 1 combined cycle unit is 300 MW.

- Controls: CO and PM/PM_{10} will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and ultra low sulfur distillate oil. NO_X emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NO_X controls, a selective catalytic reduction (SCR) system further reduces NO_X emissions during combined cycle operation.
- Continuous Monitors: The combustion turbine is required to continuously monitor NO_X emissions in accordance with the acid rain provisions. The same monitor will be employed for demonstration of continuous compliance with the Best Available Control Technology (BACT) determination. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.
- Stack Parameters: The heat recovery steam generator has a combined cycle stack (HRSG stack) that is 170 feet tall with an exit diameter of 18 feet. The following table summarizes the exhaust characteristics at 100 % load and with duct burners on.

Table 1. Exhaust Characteristics of Unit 1 at 100% Load and 26° F

Fuel	Total Heat Input CT + DB (HHV)*	Compressor Inlet Temp.	Turbine Exhaust Temp., °F	Stack Exit Temp., °F	Stack Flow ACFM
Gas	2400 mmBtu/hour	26° F	1082° F	167 ° F	1,036,793
ULS F.O.	2597 mmBtu/hour	26° F	1060° F	252° F	1,239,934

*Duct burners account for 523 mmBtu/hour on gas and 553 mmBtu/hour on oil of the total heat input.

B. PROCESS DESCRIPTION

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

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. Ambient air is drawn into the 18-stage compressor of the GE 7FA (Figure 3) where it is compressed by a pressure ratio of about 15 times atmospheric pressure. The compressed air is then directed to the combustor section, where fuel is introduced, ignited, and burned. The combustion section consists of 14 separate can-annular combustors. Figure 4 is photograph from the GE website of a "7FA on the half-shell" as viewed from the compressor section.

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower flame temperatures, which minimize NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine - section at temperatures of approximately 2500 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas is discharged at a temperature greater than 1000 °F and high excess oxygen and is available for additional energy recovery.

There are three basic operating cycles for gas turbines. These are simple, regenerative and combined cycles. In the TCEC project, the unit will operate primarily in combined cycle mode, meaning that the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). The key components of a combined cycle unit (without duct firing) are shown in the figure below. The steam is then fed to a separate steam turbine, which also drives an electrical generator producing additional electrical power. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent. This equates to a little over 50% on a higher heating value (HHV) basis.

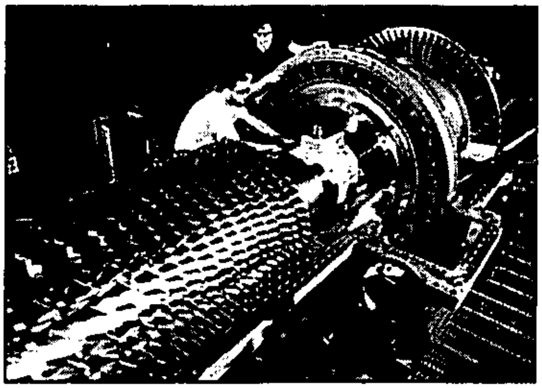


Figure 4 – Internal View - GE 7FA.

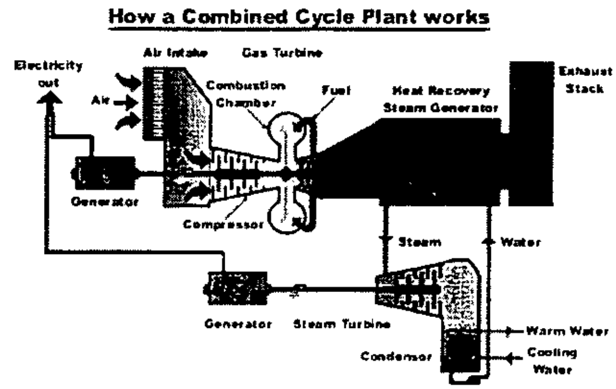


Figure 5. Components Combined Cycle Unit

The applicant has requested the following additional modes of operation.

- Fogging: Evaporative cooling (also known as "fogging") is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Fogging is typically practiced at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests unlimited use of duct burning for the unit while firing either gas or oil in the combustion turbine.

Other possibilities (not requested by FMPA) include power augmentation and peaking. Power augmentation is accomplished by returning a portion of the steam from the HRSG to the combustion turbine to increase mass flow and power output. Peaking is simply running the unit for limited time at heat input values greater than the design rating.

Additional process information related to the combustor design, and control measures to minimize NO_X formation, are given in the draft BACT determination within this evaluation.

C. POTENTIAL EMISSIONS

The project will result in emissions of nitrogen oxides, sulfur dioxides, carbon monoxide, particulate matter, sulfuric acid mist (SAM), volatile organic compounds, lead (Pb), and mercury. The following table summarizes the applicant's estimates of the annual emissions in tons per year from the proposed project. Included in these estimates are emissions from the duct burners, diesel engine fire pump, safe shutdown generator, the fuel oil storage tank for VOCs, and the cooling tower for PM/PM_{10}.

Table 2. Applicant's Estimated Potential Annual Emissions

Pollutant	Project Emissions (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required?
NO_x	90.0	40	Yes
SO_2	56.5	40	Yes
CO	228.7	100	Yes
PM	175.9	25	Yes
PM_{10}	171.3	15	Yes
VOC	23.3	40	No
SAM	22.4	7	Yes
Mercury	0.001	0.1	No
Lead	0.007	0.6	No

III. RULE APPLICABILITY

A. State Regulations

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

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

B. Federal Regulations

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

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

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

C. Description of PSD Applicability Requirements

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

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

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

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

IV. DRAFT DETERMINATION – BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

A. BACT DETERMINATION PROCEDURE

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

"Best Available Control Technology" or "BACT" – An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

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

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

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

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

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

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

The Department conducts its case-by-case BACT determinations in accordance with the requirements given above. Additionally the Department generally conducts its reviews in such a manner that the determinations are consistent with those conducted using the Top/Down Methodology described by EPA.[1]

B. NO_X BACT DETERMINATION

1. Nitrogen Oxides Formation

Nitrogen oxides form in the combustion turbine process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen.

Thermal NO_X forms in the high temperature area of the combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen, also know as the equivalence ratio. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. The changes in NO_X production as flame temperatures vary due to increasing/decreasing equivalence ratios can be seen in figure 6 below.

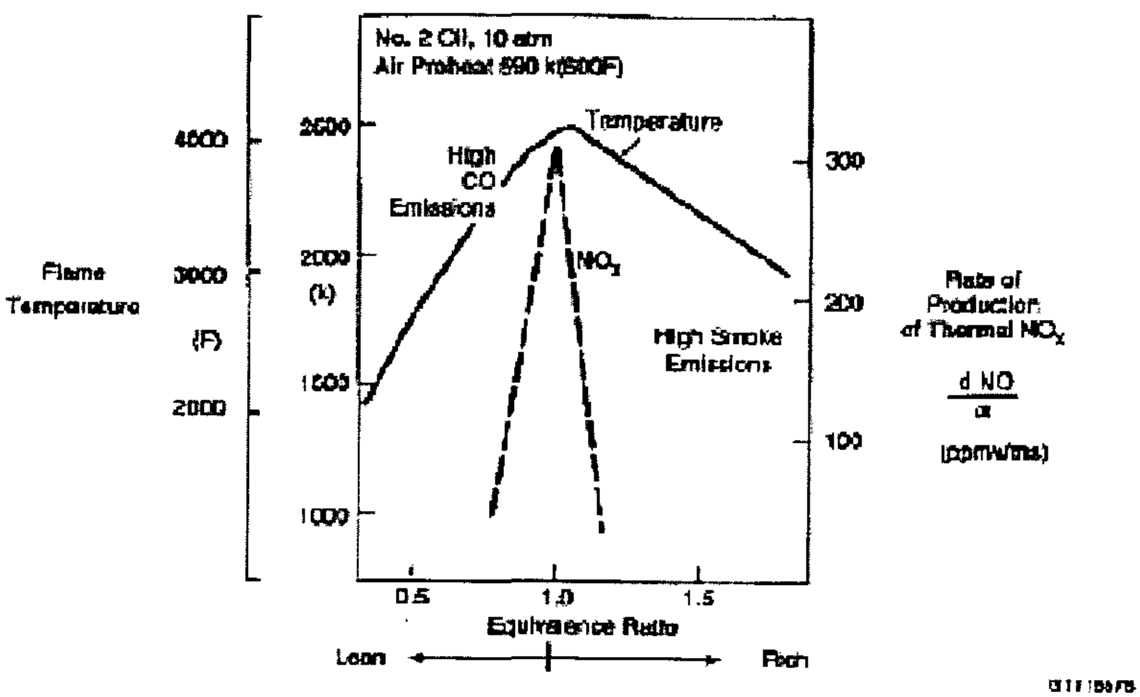


Figure 6 – NO_X Production Rate Variation With Temperature Change[2]

Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

In most combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation is depicted in Figure 7, which is from a General Electric discussion on these principles.

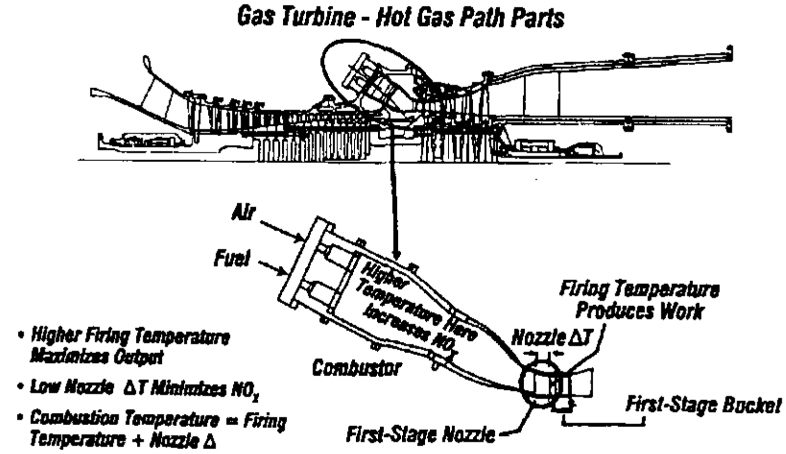


Figure 7 – Relation between Flame Temperature and Firing Temperature

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not of great concern when combusting natural gas.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for a the GE 7FA combustion turbine.[3]

2. Descriptions of Available NO_X Controls

Wet Injection. Fuel and air are mixed within traditional combustors and the combustion actually occurs on the boundaries of the flame. This is termed "diffusion flame" combustion. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can achieve NO_X emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 90% for oil firing. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques as discussed below.

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

Combustion Controls – Dry Low NO_X (DLN). The excess air in lean combustion cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is incorporated into the General Electric DLN-2.6 can-annular combustor shown in Figure 8.

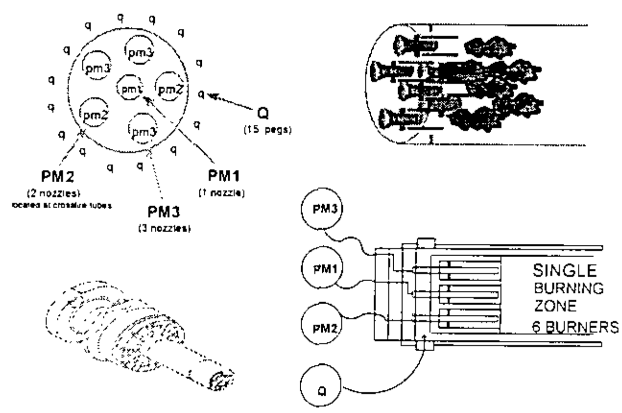


Figure 8 – DLN-2.6 Fuel Nozzle Arrangement

Each combustor includes six nozzles within which fuel and air have been fully pre-mixed. There are 16 small fuel passages around the circumference of each combustor can known as quaternary fuel pegs. The six nozzles are sequentially ignited as load increases in a manner that maintains lean pre-mixed combustion and flame stability. Design NO_X, CO, and VOC emission characteristics of the DLN-2.6 combustor while firing natural gas are given in the graph on the left side of Figure 9 for a unit tuned to meet a 9 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen). The graph on the right hand side is from a GE publication and is a plot of NO_X data from actual installations or possibly a test facility.

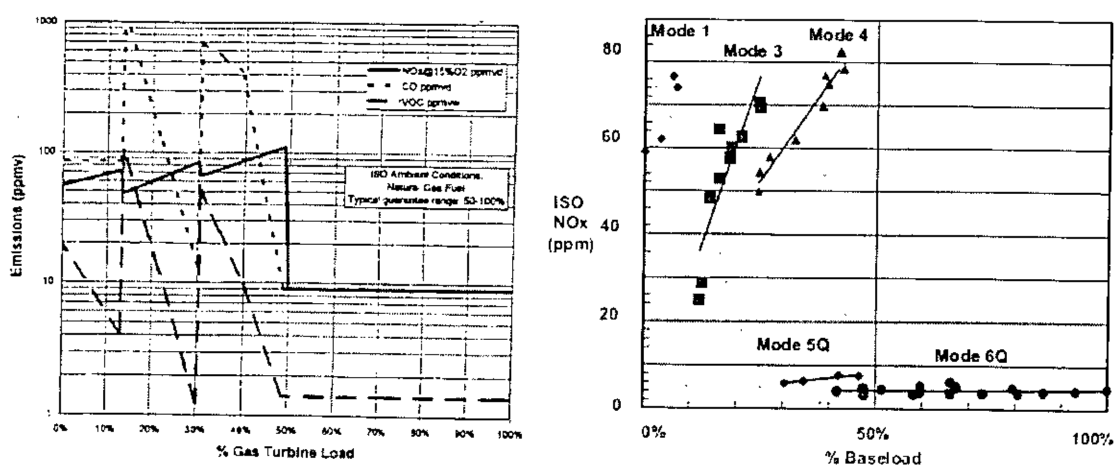


Figure 9 – Emissions Characteristics for DLN-2.6

The combustor emits NO_X at concentrations of 9 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd may occur at less than 50 percent of capacity. This suggests the need to minimize operation at low load conditions. The data plot suggests that there is at least a possibility of turndown to less than 50% of full load without excessive emissions.

Note also that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane. Actual emissions of CO and VOC have proven to be much less than suggested by the diagram.

Following are the results of the new and clean tests conducted on a dual-fuel GE 7FA combustion turbine operating in combined cycle mode and burning natural gas at the City of Tallahassee Purdom Station Unit 8.[4] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 12 ppmvd.

Table 3 – City of Tallahassee Purdom Power Plant (Station Unit 8) Test Results

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)
70	7.2	ND*
80	6.1	ND*
90	6.6	ND*
100	8.7	0.85
Limit	12	25

* Not Determined

Following are the results of the new and clean tests conducted on a dual-fuel GE PG7241FA combustion turbine operating in simple cycle mode and burning natural gas at the Tampa Electric Polk Power Station.[5] The DLN 2-6 combustors for this project were guaranteed to achieve 9 ppmvd of NO_X while burning natural gas although the permit limit is 10.5 ppmvd.

Table 4 – Tampa Electric Polk Power Station Emission Test Results

Percent of Full Load	NO_X (ppmvd @15% O_2)	CO (ppmvd)	VOC (ppmvd)
50	5.3	1.6	0.5
70	6.3	0.5	0.4
85	6.2	0.4	0.2
100	7.6	0.3	0.1
Limit	10.5	15	7

The test results at the Tallahassee and TECO projects confirm NO_X, CO, and VOC emissions less than the emission characteristics published by GE in Figure 9 above. Consistent with the discussion in the previous section, conversations with plant operators indicate that the Low NO_X characteristics extend to operations somewhat less than 50 percent of full load.[6] It is not certain whether low emissions under such operation is guaranteed by GE.

An important consideration in the effort to achieve low NO_X by combustion technology is that power and efficiency are sacrificed. This limitation is seen in Figure 10 from an EPRI report.[7] Developments such as single crystal blading, aircraft compressor design, and high technology blade cooling have helped to greatly increase efficiency and lower capital costs. Further improvements are more difficult in large part because of the competing demands for air to support lean premix combustion and to provide blade cooling. New concepts are under development by GE and the other turbine manufacturers to meet the challenges implicit in Figure 10.

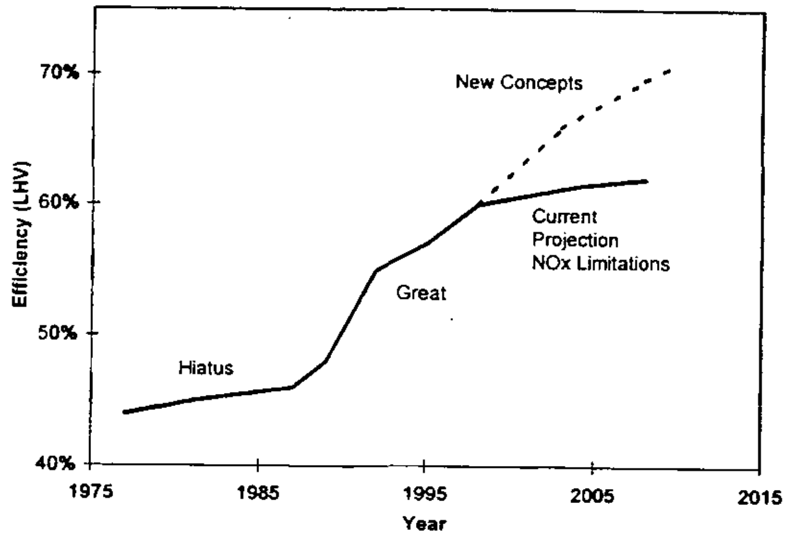


Figure 10 – Efficiency Increases in Combustion Turbines

Further NO_X reductions related to flame temperature control are possible such as closed loop steam cooling. This feature is available only in larger units (G or H Class technology) than the units planned for TCEC. It is more feasible for a combined cycle unit with a heat recovery steam generator (HRSG). In simple cycle, a once-through steam generator would be required. Steam is circulated through the internal portion of the nozzle component, the transition piece between the combustor and the nozzle, or certain turbine blades. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures (refer back to Figure 7). At the same time, thermal efficiency should be greater when employing steam cooling instead of air cooling.

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

A DLN technology known as Low Emissions Combustor (LEC) has been developed by Power Systems Manufacturing, LLC (PSM) for retrofitting existing units. LEC has been demonstrated to achieve NO_X emissions less than 5 ppmvd on combustion turbines as large as a GE7EA (nominal 85 MW excluding steam electrical production).[8] Low emissions of CO were also achieved. The company is working on versions suitable for the large GE7FA and Siemens Westinghouse products.

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

<u>Catalytic Combustion – XONON™</u>. Catalytic combustion involves using a catalytic bed to oxidize a lean air and fuel mixture within a combustor instead of burning with a flame as described above. In a catalytic combustor the air and fuel mixture oxidizes at lower temperatures, producing less NO_X.[9] In the past, the technology was not reliable because the catalyst would not last long enough to make the combustor economical.

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

Catalytica has developed a system know as XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X production) followed by flameless catalytic combustion to further attenuate NO_X formation.

In 1998, Catalytica announced the startup of a 1.5 MW Kawasaki gas turbine equipped with XONON™.[10] The turbine is owned by Catalytica and is located at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, California. This turbine and XONON™ system successfully completed over 18,000 hours of commercial operation. [11] By now, at least five such units are operating or under construction with emission limits ranging from 3 to 20 ppmvd.

Emission tests conducted through the EPA's Environmental Technology Verification Program (ETV) confirm NO_X emissions slightly greater than 1 ppm.[12] Despite the very low emission potential of XONON, the technology has not yet been demonstrated to achieve similarly low emissions on large turbines.

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

<u>Selective Catalytic Reduction (SCR)</u>. Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water according to the following simplified reaction:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium (V) and titanium oxide (TiO_2) formulations and account for most installations. At high temperatures, V can contribute to ammonia oxidation forming more NO_X or forming nitrogen (N_2) without reducing NO_X according to:

$$4NH_3 + 5O_2 \rightarrow 4NO + 6H_2O \text{ and}$$

$$4NH_3 + 3O_2 \rightarrow 2N_2 + 6H_2O$$

For high temperature applications (hot SCR up to 1100 °F), such as large frame simple cycle turbines, special formulations or strategies are required. SCR technology has progressed considerably over the last decade with Zeolite catalyst now being used for high temperature applications. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available as evidenced by both hot and conventional installations at coal-fired plants. Such improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR (low temperature) 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.

There are several examples of <u>conventional</u> SCR systems operating in Florida including:

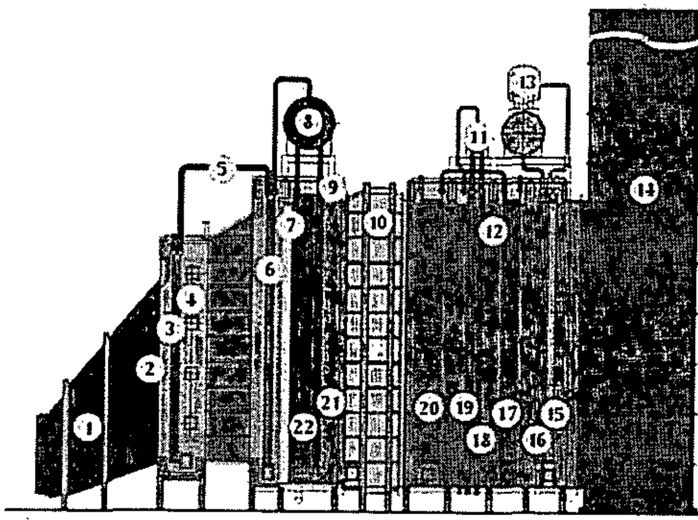
- Kissimmee Utilities Authority Unit 3. 3.5 ppmvd NO_X on gas, 12 ppmvd on fuel oil.
- Progress Energy Hines Block 2. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- JEA Brandy Branch. 3.5 ppmvd on gas and 12 ppmvd on fuel oil.
- TECO Bayside – seven combustion turbines. 3.5 ppmvd on gas.
- FP&L Manatee Unit 3. 2.5 ppmvd on gas and 10 ppmvd on fuel oil
- FP&L Martin Unit 8. 2.5 ppmvd on gas and 10 ppmvd on fuel oil.

There are several other approved projects now under construction in Florida that require <u>conventional</u> SCR systems. Most recently, DEP issued a permit for Turkey Point Unit 5 with NO_X limits of 2.0 ppmvd on gas and 8.0 ppmvd on fuel oil.

Figure 11 (Nooter-Eriksen) below is a diagram of a HRSG. Components 10 and 21 represent the SCR reactor and the ammonia injection grid. The SCR system lies between low and high-pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 12 is a photograph of the Progress Energy Hines Power Block I. The external lines to the ammonia injection grid are easily visible. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

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

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



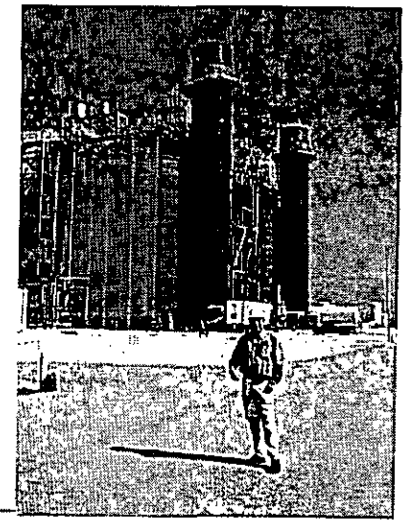


Figure 11 – Key HRSG Components (10 is SCR) **Figure 12 – PGN Hines Block I**

Following are test results from one project that is cited by EPA Region 9 to show that NO_X emissions less than 2.0 ppmvd @15% O_2 (1-hour basis) are achieved at existing large frame combustion turbine combined cycle units using SCR.[13] The units consist of two nominal 180 MW gas combustion turbine-electrical generators with unfired HRSG's, and PA capability.

Table 5. Test Results for ABB GT-24 with SCR, ANP Blackstone Energy Co., MA[14]

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

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

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

<u>SCONO$_X$™</u>. This technology is a NO_X and CO control system developed by Goal Line Environmental Technologies. Alstom Power is the distributor of the technology for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NO_X emissions

using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300°F and 700°F, which exists within a HRSG.

SCONO$_X$™ systems were installed at seven sites ranging in capacity from 5 to 43 MW.[15] None were installed at large facilities.

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

Table 6 contains averaged cost values for SCONO$_X$™ and SCR developed by the California Air Resources Board for their Legislature.[16] The comparison is for a 500-MW combined-cycle power plant consisting of two combustion gas turbines and one steam turbine meeting BACT requirements.

Table 6. Cost Comparison between SCR and SCONO$_X$ for a 500-MW Unit

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

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

Estimates provided by FMPA for the proposed 300 MW project claim even greater annual cost differences between the two technologies. While the Department does not accept or reject either set of figures, it appears that SCONO$_X$™ is not cost-effective for the present project.

3. Applicant's NO$_X$ BACT Proposal

The applicant determined that BACT for proposed Unit 1 NO$_X$ control, is the use of SCR in conjunction with Dry Low NO$_X$ burners while firing natural gas, and SCR with water injection while firing ultra low sulfur fuel oil. Fuel oil use will be limited to 500 hours per year or less.

The applicant proposed the following BACT limits for NO$_X$:

- Gas Firing: 2.0 ppmvd @ 15% O_2
- Oil Firing: 8.0 ppmvd @ 15% O_2

Note: No averaging times are specified in the application.

4. Department's Draft NO$_X$ BACT Determinations

Table 7 includes some recent BACT determinations in Florida and other states as well as some Lowest Achievable Emission Rate determinations. All used SCR. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average.

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

Table 7. Recent NO_X Standards for F-Class Combined Cycle Gas Turbine Projects

Project Location	Capacity MW	NO_X Limit ppmvd @ 15% O_2, Fuel	Comments
FPL Bellingham, MA	~ 545	1.5 (1-hr – 90% of time) 1.5 – 2.0 (10% of time)	2x170 MW GE 7FA
Sithe Mystic, MA	775	2.0 – NG (1-hr)	2x250 MW WH 501G & DBs
Towantic Energy , CT	540	2.0 NG (1-hr) 5.9 – FO	2 GE 7FA
Duke Santan, AZ	~ 900	2.0 – NG (1-hr)	3x175 MW GE 7FA & DBs
Duke Morro, CA	1,200	2.0 – NG (1-hr)	4x180 MW GE 7FA & DBs
ANP Blackstone, MA	~ 550	2.0 – NG (1-hr) 3.5 – NG/PA (1-hr)	2x180 MW ABB GT-24
FPL LLC Tesla, CA	1,140	2.0 - NG(3-hr)	4x160 MW GE 7FA &DBs
FPL Turkey Pt, FL	1,150	2.0 – NG (24-hr) 8 – FO	4x170 MW GE 7FA & DBs
Milford Power, CT	~ 550	2.0 – NG (3-hr)	2x180 MW ABB GT-24
Calpine OEC, PA	~ 550	2.0 – NG (3-hr) 2.5 – NG (1-hr)	2x182 MW WH 501F
Summit Vineyard, UT	560	2.0 – NG (3-hr)	2 WH501F & DBs
Pacificorp Currant, UT	525	2.25 – NG (3-hr)	2 GE 7FA & DBs
Cogen Tech, NJ	181	2.5 (1-hr)	181 MW GE 7FA
FPL Manatee, FL	1,150	2.5 – NG (24-hr)	4x170 MW GE 7FA & DBs
FPL Martin, FL	1,150	2.5 – NG (24-hr) 12 – FO	4x170 MW GE 7FA & DBs
PGN Hines III, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW WH501F
PGN Hines IV, FL	530	2.5 – NG (24-hr) 10 – FO	2x170 MW GE 7FA
Metcalf Energy, CA	600	2.5 – NG	2x170 MW WH 501F & DBs

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

C. CO BACT DETERMINATION

1. CO Formation and Control Options

Carbon monoxide is a product of incomplete combustion of carbon-containing fuels such as natural gas and fuel oil. Factors adversely affecting the combustion process are low temperatures, insufficient turbulence and residence times, and inadequate amounts of excess air. Most combustion turbines incorporate good combustion practices based on high temperature, sufficient time, turbulence, and excess air to minimize emissions of CO. Additional control can be obtained by installation of oxidation catalyst, particularly on combustion turbines that do not perform well at low load conditions.

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

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

Some of the more recent turbine projects within the state have been permitted with continuous emissions monitoring (CEM) requirements for CO. Continuous data from these units verify the ability of the 7FA to operate continuously with CO emission rates well below the manufacturer's guarantee. A summary of CO CEMS data recorded at TECO Bayside for 4 GE7FA units is shown in Table 8 below.

Table 8. CO CEMS Data – TECO Bayside Unit 1.

Turbine	Quarter	CO Max 24-hr Block (ppmvd)	CO Min 24-hr Block (ppmvd)	CO Quarterly Average (ppmvd)
1A	3rd Quarter 2003	4.3	0.3	0.83
1B		1.7	0	1
1C		2.1	0	0.8
1A	4th Quarter 2003	2.2	0	0.76
1B		1.9	0	1.14
1C		1.2	0	0.74

CO and VOC emissions *should* be low because of the very high combustion temperatures, excess air, and turbulence characteristic of the GE 7FA. Performance guarantees are only now "catching up" with the field experience.

GE recently published a report supporting the elimination of oxidation catalyst requirements for CO control on its units.[17] The following statement was taken from the report:

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

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

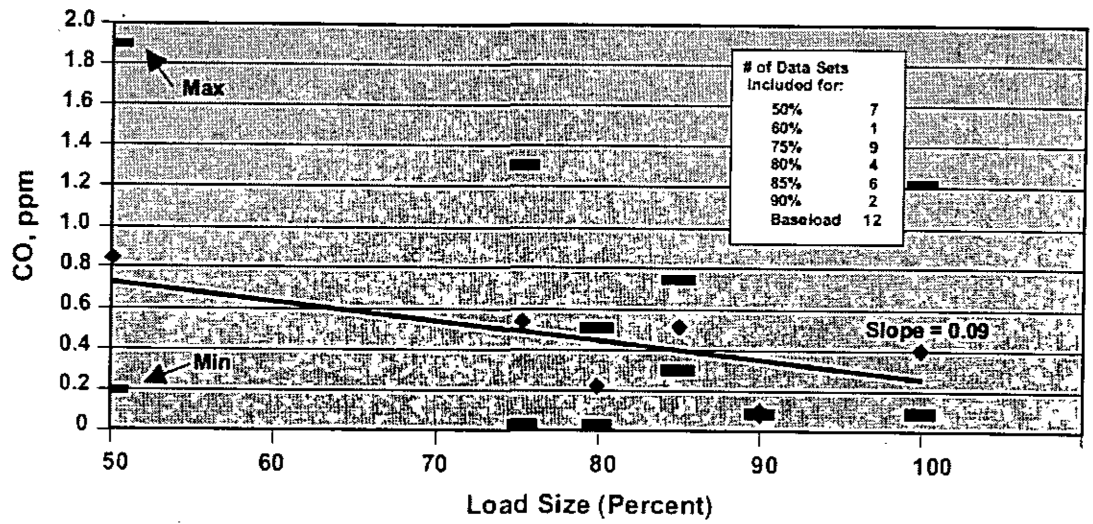


Figure 13. Average Raw CO Emissions vs. Percent Load for GE 7FA Units

2. Duct Burner and Fuel Oil Considerations

The proposed unit includes a HRSG equipped with supplemental duct firing. Turbine exhaust gas (TEG) is reheated with a gas-fired duct burner prior to entering the heater. Key HRSG components are shown in Figure 11. TEG enters the HRSG at a relatively high temperature (1,100 to 1,200 °F) and high excess air (> 12% O_2). In the design shown, some of the heat is used by a high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering a second superheater (Component 6).

Figures 14 and 15 are of an individual burner and a HRSG under construction showing horizontal duct burner elements and flow baffles. The hot TEG serves as combustion air for gas introduced into the burner array. The ignition temperature for CO is between 1,100 and 1,200 °F. All of the necessary conditions are present to minimize further CO production by the duct burner and, possibly, to incinerate CO and VOC in the TEG.

Certain configurations (NovelEdge™) are marketed to take advantage of these possibilities and to make it unnecessary to install oxidation catalyst for VOC control because of destruction by the duct burner.[18] Basically, the claim is that a "3 on 1" configuration (3 CT's & 1 HRSG) producing 750 MW can be replaced with a "2 on 1" configuration by adding very large Coen "Power Plus" DBs in a Nooter Eriksen HRSG and still produce 750 MW. The capital investments are much lower, overall efficiency is higher and the DBs destroy VOC and CO to the point that oxidation catalyst can be avoided.

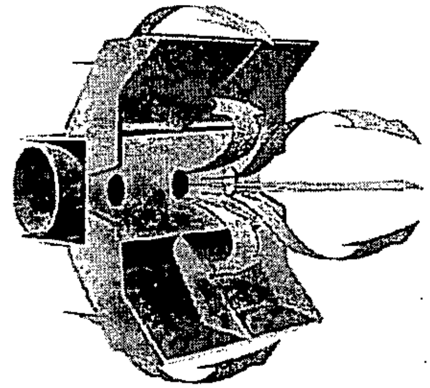


Figure 14 – Individual Burner

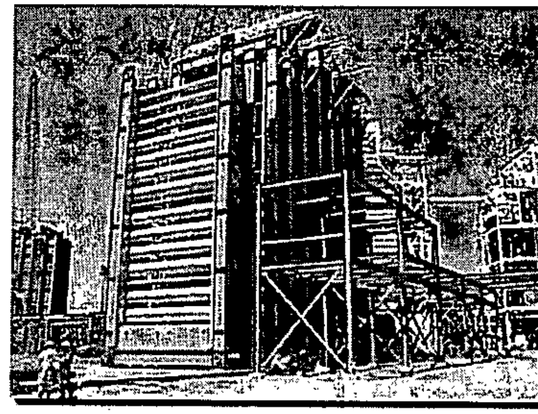


Figure 15 – Duct Burner and HRSG (Coen)

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[19] and the Southern/KUA/OUC/FMPA project at OUC Stanton. The units are GE7FA combustion turbines (CT) of the same type that will be installed at the TCEC. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 9. CO and VOC Emissions while Duct Firing – GE 7FA Units (ppmvd@15% O_2)

Unit (Modes)	CO	VOC
Gulf Smith Unit 4 (CT & DB)	1.21	0.15
Gulf Smith Unit 5 (CT & DB)	1.26	0.31
OUC Stanton Unit 25 (CT)	0.5	0.04
OUC Stanton Unit 26 (CT)	0.5	0.49
OUC Stanton Unit 25 (CT & DB)	1.6	0.2
OUC Stanton Unit 26 (CT & DB)	1.6	0.26

The Department reviewed CO and VOC data obtained during fuel oil firing at several facilities listed in Table 10 below. No appreciable differences are noted for large combustion turbines when they are operated on fuel oil versus natural gas. This conclusion is noteworthy because wet injection for basic NO_X control is practiced on all such units when firing fuel oil. The Department concludes that the low CO and VOC emissions while burning fuel oil are characteristics of the GE 7FA combustion turbines such as FMPA proposes to install at the TCEC.

Measured CO and VOC emissions were also low during a test of a GE 7FA combined cycle unit (permitted in 1999) while firing fuel oil <u>and</u> using a gas-fired duct burner. The results are given in the Table 11. FMPA does not propose fuel oil firing while using gas-fired duct burners. However this case is relevant because it combines the two modes for which FMPA requests additional emissions considerations. Even this special case indicates a reasonable expectation of low CO emissions.

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

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

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

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

3. Low Load Considerations

The full DLN features of the DLN 2.6 operate at loads greater than 50%. For that reason, the Department and most other regulatory agencies typically disallow operation at less than 50% load in most of the permits they issue for combustion turbines. In some cases the prohibition applies even at greater loads based on the features of the combustors.

FMPA personnel indicated that the proposed unit will often be operated at less than full load and that a higher CO BACT limit would be warranted. Figure 16 is a data plot from a GE publication showing how CO actually varies with respect to load. The data suggest that there is some turndown capability while emitting 7 or less ppmvd CO. This value is equal to approximately 5 to 6 ppmvd @15% O_2. The similar plot in Figure 9 suggested that NO_X emissions can also be maintained at low loads between 30 and 50% for both Modes 5Q (5 nozzles in operation) and 6Q (6 nozzles in operation), but not for Mode 4.

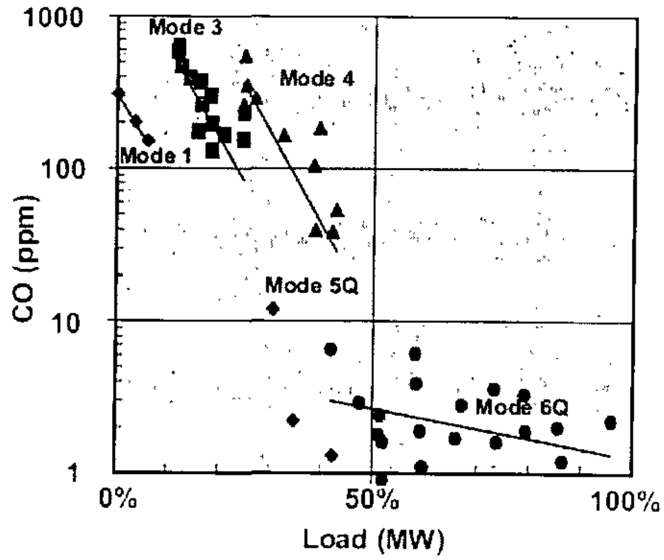


Figure 16 – Emissions Characteristics for DLN-2.6

The unit would need to operate in Mode 6Q which means that all six fuel nozzles and quaternary pegs are in operation. There is some suggestion that low CO can be maintained while operating in Mode 5Q, which is like 6Q, but without using the center nozzle. The manner by which the unit is ramped up through Modes 1, 2, 4, 5Q and 6Q and then backed down to low load cannot be inferred by this diagram. Flame stability of DLN conditions at low load is complex, and will not be addressed here.

The Department obtained data from operations at JEA Brandy Branch.[25] They are summarized in the following table. For reference 65 MW represents roughly 38% of full load. According to the utility, GE offers the software to tune and operate under the described conditions. A utility representative said that the unit operated in Mode 6Q during the tests.[26]

Table 12. CO Emissions during Low Load Operation at JEA Brandy Branch Unit 1

Test/Run	Load (MW)	Load (% full load)	CO (ppm)	CO (ppm) @15%O_2)
1/1	65	38	9.6	8.5
1/1	65	38	9.0	8.0
1/3	65	38	9.2	8.1
2/1	65	38	12.2	10.7
2/2	65	38	12.2	10.7
2/3	65	38	11.9	10.5
3/1	65	38	12.3	10.9
3/2	65	38	11.9	10.5
3/3	65	38	12.1	10.6

4. Applicant's CO BACT Proposal

The applicant has proposed BACT for CO as the use of good combustion controls while firing natural gas or ULS in accordance with the defined operating hours for each fuel. FMPA concluded that oxidation catalyst for the removal of CO is not cost effective. In the response dated July 28 to the Department's Notice of Insufficiency, FMPA requested the BACT limit for CO be set at 8.0 ppmvd while firing natural gas and 12.0 ppmvd while firing fuel oil based on 24-hr block averaging times.

Table 13 below contains the emissions guarantees for CO submitted to the Department by FMPA for the TCEC project. The values are "uncorrected". For reference the value of 5 ppmvd equates to approximately 4.1 ppmvd @15% O_2. Similar corrections apply to the other values cited.

Table 13. CO Guarantee Information Submitted by FMPA

Fuel	CO Guarantee (ppmvd)	Load Range (%)	Ambient Range (°F)
Natural Gas	5.0	50 - 100	35 - 85
Natural Gas	5.0	60 - 100	>85 - 100
Natural Gas	9.0	50 - <60	>85 - 100
Natural Gas	9.0	50 - 100	26 - <35
Fuel Oil	8.0	75 - 100	26 - 100
Fuel Oil	20.0	50 - <75	26 - 100

The guaranteed value for CO emissions is 5 ppmvd (4.1 ppmvd @15% O_2) while burning natural gas at loads between 60 and 100 percent. A higher limit of 9 ppmvd is guaranteed for very low temperature conditions that are infrequent at the proposed site. The same value is proposed when the ambient temperature is greater than 85 °F.

The Department has no data to support the need for the greater value at higher temperatures. Actually at such temperatures, the inlet air will be subjected to evaporative cooling and operation will simulate normal temperature ranges. Also, if the unit is operated at a higher heat input rate to try to recover some of the lost power at high ambient temperature, the firing temperature will increase and CO will probably decrease.

A limit of 8 ppmvd is guaranteed while burning fuel oil. However, according to Table 10 above, CO emissions while burning fuel oil are actually very low, even at 50 percent of full load. There does not appear to be a solid basis for the relatively high 20 ppmvd guaranteed value between 50 and 75 percent of full load.

5. Department's Draft CO BACT Determinations

Table 14 includes some recent BACT determinations for CO (and VOC and PM) in Florida and other states. FMPA's proposal is included for comparison. Most of the projects cited required oxidation catalyst. The "Top" emission limit is considered by the Department to be 2.0 ppmvd @15% O_2 on a 1-hour average. The limit is achievable by use of oxidation catalyst.

Table 14. CO, VOC, and PM Standards for "F-Class" Combined Cycle Units

Project Location	CO - ppmvd (@15% O_2)	PM - lb/mmBtu (or gr/dscf or lb/hr)
FPL Bellingham, MA	2.0 (3-hr – Ox-Cat)	0.008
Sithe Mystic, MA	2.0 (1-hr – Ox-Cat)	0.008 (NH_3 = 2.0 ppmvd)
Duke Santan, AZ	2.0 (3-hr – Ox-Cat)	0.01
Duke Morro, CA	2.0 (Ox-Cat)	0.0059 (DB off) 0.0064 (DB on)
ANP Blackstone, MA	3.0 (Ox-Cat)	0.002 (NH_3 = 2.0 ppmvd)
FPL LLC Tesla, CA	4.0 – NG (3-hr – Ox-Cat)	0.0048 (NH_3 = 5 ppmvd) 0.0005 Cool Tower Drift
FPL Turkey Pt., FL	4.1 – NG (DB off, AnnualTest) 7.6 – NG (DB on, Annual Test) 14 – NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	11 lb/hr – NG (Front ½) 14.4 lb/hr – NG (DB on) 17.6 lb/hr – FO (Front ½) 10% Opacity – All Modes
FMPA TCEC, FL	8.0 NG (24-hr block) 12.0 FO (24-hr block)	38.0 lb/hr – NG (front + back ½) 52 lb/hr – FO (front + back ½)
Milford Power, CT	13 – 52 lb/hr (Ox-Cat)	0.011
Calpine OEC, PA	10 (1-hr)	0.0061
Cogen Tech, NJ	2.0 (1-hr – Ox-Cat)	
FPL Manatee, FL	8 – NG (DB off) 10 – NG (DB, PA)	10% Opacity NH_3 = 5
FPL Martin, FL	7.4 – NG (New, Clean) 8.0 – NG (DB off) 10 – (DB, PA)	10% Opacity NH_3 = 5
PGN Hines IV, FL	8.0 - NG 12.0 – FO	10% Opacity NH_3 = 5
El Paso Manatee, FL	2.5 – NG (3-hr – Ox-Cat) 4 – NG (3-hr, PA)	20 lb/hr – (Front & Back) 5 ppmvd Ammonia Slip
Metcalf Energy, CA	6 - NG (100% load)	12 lb/hr – NG (w DB) 5 ppmvd Ammonia Slip
Enron/Ft. Pierce, FL	3.5 – NG (Cat-Ox) 10 - Low Load 8 - FO	10% Opacity

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

With oxidation catalyst a GE 7FA will likely achieve CO values much less than 2 ppmvd @15% O_2. The actual performance would likely be as good or better than the GT-24 example given in Table 5. That unit had CO characteristics ranging from ~0 to 0.8 ppmvd @15% O_2 at 50% or more of full load. Although the GE 7FA will be guaranteed to achieve 5 ppmvd (4.1 ppmvd @15% O_2), the data suggest typical emissions without oxidation catalyst that are approximately equal to the emission limit of 2 ppmvd @15% O_2 given above as "Top" control.

If the unit fired only natural gas and did not experience the other operating modes, it would be straightforward to conclude that the cost of oxidation catalyst would not be justified because the cost to reduce "permitted emissions" from 5 to 2 ppmvd @15% O_2 would not be cost-effective. This is in agreement with the conclusion in the GE paper cited in the discussion leading to Figure 13 above.

Notwithstanding the guarantees given in Table 13, the data available to the Department suggests that CO emissions from the GE 7FA are also inherently low for the duct firing and fuel oil use modes. They are also inherently low to loads equal to 50%. At loads less than 50%, they can be maintained close to 10 ppmvd @15% O_2 while operating the unit with natural gas and in the 5Q or 6Q DLN modes. Some consideration can be given for the time that the unit will actually operate in those modes, in the same manner as consideration is given to increased CO emissions from limited power augmentation at other projects.

BACT for CO is determined to be the 5.0 ppmvd (4.1 ppmvd @ 15% O_2) for natural gas firing and the 8.0 ppmvd (7.6 ppmvd @ 15% O_2) for fuel oil firing. A continuous limit of 8.0 ppmvd @15% O_2 on a 24-hour basis will be implemented for both gas and oil firing, with or without the duct burner in operation.

An annualized limit of 6 ppmvd @15% O_2 will also be included in recognition of the preponderance of the time when the unit will be operated in the normal natural gas mode and the reality that most modes are characterized by inherently low emissions.

The limited time during which the unit will be operated at low load can be accommodated within this limit based on the data presented above. If extensive operation at loads less than 50% is foreseen, then the situation described in the GE paper would revert to the case where oxidation catalyst is indicated. In that case, CO emissions of 10 ppmvd or greater could be controlled to 2 ppmvd or less by oxidation catalyst.

The Department's BACT determination is the same as that issued for the FPL Turkey Pt. Project. The impacts of the modes (beyond the simple case of natural gas use at 50-100% load) are about equal for the two projects. In contrast to permits for other facilities in Florida and other states, it will not be necessary to prohibit low load operation because the behavior of emissions at lower loads is no longer unknown. Emissions limits can still be met with some operation between 40 and 50 % load.

For reference, FMPA estimated the cost of CO removal by oxidation catalyst to be approximately $3,400 per ton. While the Department does not necessarily agree with this estimation, oxidation catalyst would not be cost-effective for this unit given that the Department's BACT determination is implemented.

In summary, the Department will set the following BACT limits:

- Gas Firing: 8.0 ppmvd @ 15% O_2 (24-hr average)
  Without DB: 4.1 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  With DB: 7.6 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr limit)
  Low Load: (included in 24-hr limit)
- Oil Firing: 8.0 ppmvd @ 15% O_2 (3-hr annual test and included in 24-hr average)
- All Modes: 6.0 ppmvd @ 15% O_2 (12-month average)

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

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

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

For this project, the applicant has proposed as BACT, for SO_2 and SAM, the use of pipeline natural gas and limited use (500 hrs or less) of ultra low sulfur diesel fuel oil with less than 0.0015 percent sulfur by weight as BACT. For reference, the sulfur limit given in New Source Performance Standard, 40 CFR 60, Subpart GG applicable to combustion turbines is 0.8 percent by weight.

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

1. PM/PM_{10} Formation and Control Options

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

Natural gas and ultra low sulfur fuel oil are efficiently combusted in gas turbines and will be the only fuels fired in the proposed unit. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The ULS fuel oil to be combusted contains a minimal amount of ash and will be used for less than 500 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

2. Other PM/PM_{10} Considerations

<u>Ammonia Slip and Ammonium Salts Formation</u>: Emissions of NO_X, SO_2, and SAM are ultimately converted to very fine nitrate and sulfate species in the environment such as ammonium nitrate and ammonium sulfate. Because PM/PM_{10} emissions can be increased due to the formation of these ammonium salts prior to exiting the stack, it is important to limit ammonia emissions (known as slip) originating from the SCR NO_X control technology. Elevated levels of ammonia slip can also be an indication of a degrading catalyst. The Department proposes an ammonia limit of 5 ppmvd @ 15% O_2.

Cooling Tower PM Emissions: Small amounts of water entrained in the air passing through a wet cooling tower can be carried out of the tower and are known as "drift" droplets. Because the droplets contain impurities from the cooling water, the particulate matter constituent of the drift droplets may be classified as an emission[27]. The amount of particulates that may be emitted are based on the solids loading in the re-circulating water.

The applicant's proposal includes an 8-cell, 111,130 gallon per minute (gpm) mechanical draft cooling tower with drift eliminators with a design drift rate of 0.0005% of design water flow. FMPA estimates annual PM and PM_{10} emissions from the cooling tower to be 6.48 TPY and 1.87 TPY respectively.

3. Applicant's PM/PM_{10} Proposal

The applicant determined that BACT for proposed Unit 1 PM/PM_{10} is good combustion controls and the use of good natural gas, ultra low sulfur fuel oil.

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

The following conditions are established as the draft BACT standards.

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

The Department notes that the described measures minimize emissions and formation of fine particulate matter classified as $PM_{2.5}$. The described strategy directly reduces PM emissions as well as formation of ammoniated particulate matter. Finally the NO_X and SO_2 control minimizes emissions of precursors known to contribute to formation of $PM_{2.5}$ in the environment.

F. BACT Considerations for Auxiliary Equipment

Safe Shutdown Generator: The safe shutdown generator (an approximately 765 hp diesel engine) will be used when the transmission connection to the plant is lost. The generator will be operated to provide power to the plant in a safe shutdown condition when needed, and for periodic testing throughout the year to ensure operability.

Diesel Engine Fire Pump: The diesel engine fire pump (an approximately 300 hp diesel engine) falls under the categorical emission unit exemption for fire and safety equipment (Rule 62-210.300(3)(a)22, F.A.C.) Like the safe shutdown generator, the fire pump will be operated only during emergency situations and for periodic testing throughout the year.

Use of ultra low sulfur fuel oil and limited operation (200 hours or less) ensure that emissions from both the safe shutdown generator and the diesel engine fire pump will be minimal. However, projected potential emissions from both units are included in the project potential to emit calculations and the ambient air quality impact analysis.

G. Summary of Department Draft BACT Determination

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

Table 15. Draft BACT Determination – Treasure Coast Energy Center Unit 1

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
		CT, Low Load	NA	NA	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X [b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10} [c]	Oil/Gas	All Modes	Fuel Specifications Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	Oil/Gas	All Modes	2 gr S/100 SCF of gas, 0.0015% sulfur fuel oil		
Ammonia [e]	Oil/Gas	CT, All Modes	5.0	NA	NA

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

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

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

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

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

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

V. NEW SOURCE PERFORMANCE STANDARDS

A. Combustion Turbines

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

- NO_X (gas) ≤ 109 ppmvd @ 15% O_2 (corrected for heat rate of 9,355 Btu/KW-h LHV at peak load, evaporative cooler on) and;
- NO_X (oil) ≤ 101 ppmvd @ 15% O_2 (corrected for a heat rate of 10,120 Btu/KW-h LHV at peak load, evaporative cooler on); and
- SO2 emissions are limited to < 0.015 percent by volume at 15% O2 on a dry basis (150 ppmvd) or by the use of a fuel with a sulfur content of no more than 0.8% by weight (8000 ppmw).

A more recent standard was proposed by EPA on February 18, 2004. The proposed standard, 40 CFR60, Subpart KKKK would require adherence to the following limits:

- NO_X (gas) ≤ 0.39 lb/megawatt-hour. This is approximately equal to 11 ppmvd @15% O_2 for this turbine.
- NOX (oil) ≤ 1.2 lb/megawatt-hour. This is approximately equal to 33.5 ppmvd @15% O_2 for this turbine.
- SO2 emissions are limited by the use of a fuel with a sulfur content of no more than 0.05% (500 ppmw) by weight.

The final rule will be applicable to TCEC Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

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

B. Duct Burners

The heat recovery steam generator has gas-fired duct burners with a maximum heat input rate of 554 MMBtu per hour (HHV). This subjects the duct burners to the federal New Source Performance Standards in Subpart Da of 40 CFR 60, which applies to combined cycle units with a heat input rate from fossil fuel of more than 250 MMBtu per hour. The following emissions standards apply:

- NO_X ≤ 1.6 lb/MW-hr (gross)

The proposed BACT standards for the combination of gas turbine and duct burner emissions are less than 0.1 lb/MW-hr for NO_X. This will insure that the NSPS NO_X emission limit for the duct burners will easily be met. For example, if emissions from a duct burner alone exceeded its NSPS standards, then emissions from the duct burner and associated combustion turbine combined would exceed the BACT limits. An Appendix to the permit will summarize applicable federal requirements.

VI. PERIODS OF EXCESS EMISSIONS

A. Excess Emissions Prohibited

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

B. Alternate Standards and Excess Emissions Allowed

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

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

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

- Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.
- For oil-to-gas fuel switching excess emissions shall not exceed 1 hour in any 24-hour period.
- Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.
- For warm startup, up to four hours of excess emissions are allowed. "Warm startup" is defined as a startup following a shutdown lasting between 8 and 48 hours.
- For cold startup to combined cycle operation, up to six hours of excess emissions are allowed. "Cold startup" is defined as a startup following a shutdown lasting at least 48 hours.
- For shutdown, up to three hours of excess emissions are allowed.

- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.

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

<u>DLN Tuning</u>: Dry Low NOX combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NOX and CO emissions, and extends the life of the unit components. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Excess emissions of NOX, CO, and opacity are allowed during DLN tuning sessions provided the proper notification is provided to the Compliance Authority. Notification two weeks prior to tuning will be required.

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

VII. AIR QUALITY IMPACT ANALYSIS

A. INTRODUCTION

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, NO_X, SO_2 and SAM. PM_{10}, SO_2 and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, significant impact levels and de minimis monitoring levels defined for them. CO is a criteria pollutant and has only AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for SAM.

B. MAJOR STATIONARY SOURCES IN ST. LUCIE COUNTY

The current largest stationary sources of air pollution in St. Lucie County are listed below. The information is from annual operating reports submitted to the Department.

Table 16. MAJOR SOURCES OF NO_X IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	*Blue Heron Energy Center (proposed)*	*313*
Florida Gas Transmission (FGT)	FGT Station 20	261
Florida Municipal Power Agency	*Treasure Coast Energy Center (proposed)*	*91*
Tropicana Products	Tropicana Products	45
Fort Pierce Utilities Authority	HD King Power Plant	30

Table 17. MAJOR SOURCES OF SO_2 IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Calpine	*Blue Heron Energy Center (proposed)*	**226**
Florida Municipal Power Agency	*Treasure Coast Energy Center (proposed)*	*58*
Dickerson Florida, In	Dickerson/Asphalt Plant #14	10

Table 18. MAJOR SOURCES OF PM/PM_{10} IN ST. LUCIE COUNTIES (2003)

Owner/Company	Site Name	Tons per year
Calpine	*Blue Heron Energy Center (proposed)*	**264**
Florida Municipal Power Agency	*Treasure Coast Energy Center (proposed)*	*176*
Tropicana Products	Tropicana Products	22
Cargill Juice North America	Ft. Pierce	9

Table 19. MAJOR SOURCES OF CO IN ST. LUCIE COUNTY (2003)

Owner/Company	Site Name	Tons per year
Florida Municipal Power Agency	*Treasure Coast Energy Center (proposed)*	*234*
Tropicana Products	Tropicana Products	169
Cargill Juice North America	Ft. Pierce	160
Calpine	*Blue Heron Energy Center (proposed)*	**156**
Florida Gas Transmission (FGT)	FGT Station 20	111

C. AIR QUALITY AND MONITORING IN ST. LUCIE COUNTY

The Southeast District in West Palm Beach operates four monitors at one site in St. Lucie County measuring PM_{10}, $PM_{2.5}$, ozone, and NO_2. The monitoring site is shown in the figure below.

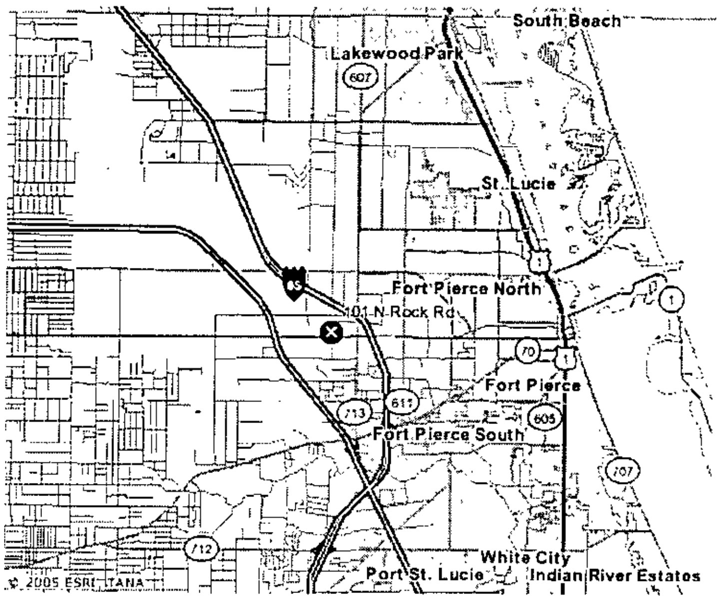


Figure 17. St. Lucie Monitoring Site

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

Table 20. Ambient Air Quality Nearest to Project Site (2003)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ft. Pierce	24-hour	65	43		150 [a]	ug/m^3
		Annual			17	50 [b]	ug/m^3
SO_2	Riveria Beach	3-hour	4	3		500 [a]	ppb
		24-hour	2	2		100[a]	ppb
		Annual			1	20 [b]	ppb
NO_2	Ft. Pierce	Annual			9	53 [b]	ppb
CO	West Palm Beach	1-hour	5	4		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Ft. Pierce	1-hour	0.081	0.076		0.12 [C]	ppm
		8-hour	0.071	0.071		0.08 [C]	ppm

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

St. Lucie County/The Southeast District does not monitor for Sulfur Dioxide or Carbon Monoxide. Therefore the data for these pollutants are not representative of air quality near the proposed plant site. However, measurements at sites throughout the state that are in the vicinity of larger SO_2 and CO sources than the proposed plant are also in attainment with the respect to the SO_2 and CO NAAQS. Therefore it is reasonable to conclude that SO_2 and CO concentrations near the project site are also in attainment of the SO_2 and CO NAAQS.

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

D. AIR QUALITY IMPACT ANALYSIS

1. Significant Impact Analysis

Significant Impact Levels (SILs) are defined for PM/PM_{10}, CO, NO_X and SO_2. A significant impact analysis is performed on each of these pollutants to determine if a project can even cause an increase in ground level concentration greater than the SIL for each pollutant. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class I (Everglades National Park - ENP and the Chassahowitzka National Wildlife Refuge -CNWR) and PSD Class II Areas (everywhere except the Class I areas).

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

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

Table 21. Maximum Projected Air Quality Impacts from Treasure Coast Energy Center Project for Comparison to the PSD Class II Significant Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m3)	Significant Impact Level (ug/m3)	Baseline Concentrations (ug/m3)	Ambient Air Standards (ug/m3)	Significant Impact?
SO_2	Annual	0.1	1	~3	60	NO
	24-Hour	1	5	~5	260	NO
	3-Hour	3	25	~10	1300	NO
PM_{10}	Annual	0.2	1	~17	50	NO
	24-Hour	4.2	5	~65	150	NO
CO	8-Hour	17	500	~2300	10,000	NO
	1-Hour	27	2000	~5750	40,000	NO
NO_2	Annual	0.1	1	~17	100	NO

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

The nearest PSD Class I area is the Everglades National Park (ENP) located about 180 km to the south-southwest west of the project site. The CWNR is located about 260 km to the northwest of the project site. Maximum air quality impacts from the proposed project are summarized in the following table. The results of the initial PM/PM_{10}, NO_X and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from SO_2, PM_{10}, and NO_2 are less than the applicable SILs for the Class I areas. Therefore no further detailed modeling efforts are required.

Table 22. Maximum Air Quality Impacts from the Treasure Coast Energy Center Project for comparison to the PSD Class I SILs at ENP

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Class I Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.003	0.2	NO
	24-hour	0.05	0.3	NO
NO_2	Annual	0.001	0.1	NO
SO_2	Annual	0.0005	0.1	NO
	24-hour	0.01	0.2	NO
	3-hour	0.03	1	NO

The Maximum Air Quality Impacts for comparison to the PSD Class I SILs at CWNR are less than the impacts at ENP.

2. Preconstruction Ambient Monitoring Requirements

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

Table 23. Maximum Air Quality Impacts vs. the De Minimis Ambient Impact Levels

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
PM_{10}	24-hour	4	10	~65	NO
NO_2	Annual	0.1	14	~17	NO
SO_2	24-hour	1	13	~5	NO
CO	8-hour	17	575	~2300	NO

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

- An analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

3. Models and Meteorological Data Used in the Air Quality Analysis

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

The ISCST3 model allows for the separation of sources, building wake downwash, and various other input/output parameters. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfied the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from West Palm Beach. The 5-year period of meteorological data was from 1987 through 1991. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and ceiling.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I ENP and CWNR beyond 50 km from the proposed project. Meteorological data used in this model was from the National Weather Service West Palm Beach as with the ISCST3 model.

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

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

E. ADDITIONAL IMPACTS ANALYSIS

1. Impact on Soils, Vegetation, and Wildlife

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

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

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

According to the applicant, the maximum predicted deposition rates were located in the ENP. The impacts of the deposition rates of sulfur and nitrogen, 0.00051 and 0.00097 kg/ha/yr respectively, are still much less than the buffering capacities of the soils in the ENP and much less than the observed deposition rates existing in the area.

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

The National Park Service and Fish and Wildlife Service do not anticipate any significant impacts with regards to AQRV's in the ENP and CWNR from the proposed project.

2. Impact on Visibility and Regional Haze

The applicant submitted a regional haze analysis for the ENP and CWNR. The analysis included modeling from the CALPUFF model. The CALPUFF model predicts modeled impacts well below the 5% visibility impairment based on criteria from the NPS.

The National Park Service and Fish and Wildlife Service do not anticipate any significant visibility impacts in the ENP and CWNR from the proposed project.

3. Growth-Related Impacts Due to the Proposed Project

There will be short-term increases in the labor force to construct the project. According to the applicant, about 286 additional workers will be needed over the 11-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the project will require 16 new permanent employees, which will cause no significant impact on the local area.

4. Growth-Related Air Quality Impacts since 1977

According to the applicant, St. Lucie County is the 3rd fastest growing county in Florida. Residential growth in the area of the proposed project, St. Lucie County, has nearly tripled from 1977 to 2005. The county has continued to be in attainment with all National Ambient Air Quality Standards.

5. Endangered Species Considerations

The purpose of the Endangered Species Act (ESA) is to conserve "the ecosystems upon which endangered and threatened species depend" and to conserve and recover listed species.[28] Under the law, species may be listed as either "endangered" or "threatened".

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

While state PSD permits are not generally reviewed for adherence with the Endangered Species Act, the State of Florida's Power Plant Certification process requires an assessment of existing ecology and determination of project impacts. Sections 2.3 and 4.4 of the Site Certification Application include a characterization of the existing environment, and an ecological impacts assessment including wildlife and threatened and endangered species. The applicant concludes that the project will not have an adverse effect on endangered species.

According to the U. S. Fish and Wildlife Service (F&WS) website there were 111 threatened or endangered species (per the federal list) in Florida on May 18, 2004.

The reader is referred to the following website:

http://ecos.fws.gov/tess_public/TESSWebpageUsaLists?state=FL

Threatened and endangered animal species observed within a five mile radius of the TCEC site include several bird species such as the bald eagle, the Florida sandhill crane, and the snail kite. The Sherman's fox squirrel and eastern indigo snake have also been observed within this area. According to the application, there are no federal or Florida listed threatened or endangered species known to occur on the site or in close proximity. There is one bald eagle nest, however northwest of the site, of which the exact location is not known. The bald eagle is protected in accordance with the Endangered Species Act, Bald and Golden Eagle Protection Act, and the guidance document entitled *Habitat Management Guidelines for the Bald Eagle in the Southeast Region*, issued by the U.S. Fish and Wildlife Service. FMPA has committed to consulting the U.S. Fish and Wildlife Service on how to best avoid disturbing the nest during site development and operation.

Figure 18. Nesting Eagle in South Florida

Figure 19. Eagle Pair in SW Florida

FMPA has already contacted both the U.S. Fish and Wildlife Service and the Florida Fish and Wildlife Conservation Commission by letter requesting review of the proposed project.[29, 30]

VIII. PRELIMINARY DETERMINATION

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

Cindy Mulkey is the project review engineer and is responsible for preparing the draft permit conditions. She may be contacted at cindy.mulkey@dep.state.fl.us and 850-921-8968. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Alvaro Linero, P.E., is the Section Adminstrator. He reviewed, contributed to and affixed his seal on this Techncial Evaluation and Preliminary Determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

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Daniel Cassel, Director of Generation

Treasure Coast Energy Center
DEP File No. 1110121-001-AC
Permit No. PSD-FL-353
SIC No. 4911
Expires: July 31, 2008

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 MW gas-fired combined cycle electrical power plant. The project will include one 170 MW combustion turbine generator, one heat recovery steam generator, a 130 MW steam turbine generator, a fuel oil storage tank, a mechanical draft cooling tower, and auxiliary equipment. The project will be located southwest of the city of Fort Pierce, East of Highway 95 in St. Lucie County.

STATEMENT OF BASIS

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

The attached Appendices are made a part of this permit:

Appendix A	NSPS Subpart A, Identification of General Provisions
Appendix BD	Final BACT Determination and Emissions Standards
Appendix Da	NSPS Subpart Da Requirements
Appendix GC	Construction Permit General Conditions
Appendix GG	NSPS Subpart GG Requirements
Appendix SC	Standard Conditions

Michael G. Cooke, Director
Division of Air Resources Management

Date:_______________

SECTION I - GENERAL INFORMATION

FACILITY DESCRIPTION

The proposed FMPA facility is a combined cycle power plant. The project is to install one combined cycle unit which will consist of one gas turbine (nominal 170 MW) and one heat recovery steam generator with supplementary duct firing, a steam turbine-electrical generator (nominal 130 MW), a mechanical draft cooling tower, and one 990,000 gallon fuel oil storage tank. Ancillary equipment includes a diesel engine driven fire pump with associated 500 gallon fuel oil tank, and a safe shutdown generator.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions unit:

EU ID NO.	EMISSION UNIT DESCRIPTION
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

REGULATORY CLASSIFICATION

Title III: The facility is not a "Major Source" of hazardous air pollutants (HAPs).

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

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

PSD: The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for, each pollutant subject to a National Ambient Air Quality Standard. It is classified as a "fossil fuel-fired steam electric plant of more than 250 million BTU per hour of heat input", which is one of the 28 Prevention of Significant Deterioration (PSD) Major Facility 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., Prevention of Significant Deterioration of Air Quality.

NSPS: Unit 1 is subject to 40 CFR 60, Subparts GG (Standards of Performance for Stationary Gas Turbines) and Da (Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978). When the proposed NSPS Subpart KKKK (Standards of Performance for Stationary Combustion Turbines for Which Construction is Commenced After February 18, 2005) becomes final, the facility will be subject to Subpart KKKK, and may no longer be subject to subparts GG and Da. The distillate fuel oil tank has a capacity greater than or equal to 40,000 gallons (151 cubic meters) and is storing a liquid with a maximum true vapor pressure less than 3.5 kPa, and is therefore not subject to Subpart Kb.

NESHAP: The facility is not a "Major Source" of HAPs and Unit 1 is not subject to 40 CFR 63, Subpart YYYY, National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Gas Turbines.

Siting: The facility is a steam electrical generating plant and is subject to the power plant siting provisions of Chapter 62-17, F.A.C.

PERMITTING AUTHORITY

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

COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection Southeast District, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida 33401.

APPENDICES

The following Appendices are attached as part of this permit.

Appendix A. NSPS Subpart A, Identification of General Provisions

Appendix BD. Final BACT Determinations and Emissions Standards

Appendix 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

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit; however, they are specifically related to this permitting action and are on file with the Department.

- Application received on April 14, 2005
- Department's Determination of Sufficiency – Found Insufficient June, 6 2005
- FMPA Sufficiency responses dated July 28, 2005
- Department's Second Determination of Sufficiency – Found Sufficient August 29, 2005
- Department's Intent to Issue and Public Notice Package dated October 28, 2005
- Letter from EPA Region IV dated __XXX________
- Final Certification by the Power Plant Siting Board on XXXX; and
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

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

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

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

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

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

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

7. Title V Permit: This permit authorizes construction of the permitted emissions unit and initial operation to determine compliance with Department rules. A Title V operation permit is required for regular operation of the permitted emission units. The permittee shall apply for and obtain a Title V operation permit in accordance with Rule 62-213.420, F.A.C. 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 a copy to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

A. Unit 1 Combined Cycle Gas Turbine (EU 001)

This section of the permit addresses the following emissions unit.

E.U. ID	Emission Unit Description
001	Unit 1 consists of a General Electric PG7241 FA gas turbine electrical generator (nominal 170 MW) equipped with evaporative inlet air cooling, a heat recovery steam generator (HRSG) with supplemental duct firing, a HRSG stack, and a steam turbine electrical generator (nominal 130 MW).

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: The emission unit addressed in this section is subject to a Best Available Control Technology (BACT) determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the New Source Performance Standards for Subpart Da, Subpart GG, and Subpart KKKK (as proposed). Some separate reporting and monitoring may be required by the individual subparts.

   (a) **Subpart A, General Provisions**, 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
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Subpart Da, Standards of Performance for Electric Utility Steam Generating Units** These provisions include standards for duct burners.

   (c) **Subpart GG, Standards of Performance for Stationary Gas Turbines:** These provisions include a requirement to correct test data to ISO conditions; however, such correction is not used for compliance determinations with the BACT standards.

   (d) **Subpart KKKK, Standards of Performance for Stationary Gas Turbines:** These provisions were published February 18, 2004 as a proposed new NSPS standard. The final rule will be applicable to Unit 1 at the time of publication in the Federal Register. When the rule becomes final, Unit 1 may no longer be subject to NSPS Subparts Da and GG.

EQUIPMENT

3. Gas Turbine: The permittee is authorized to install, tune, operate, and maintain one General Electric Model PG7241FA gas turbine-electrical generator set with a nominal generating capacity of 170 MW. The gas turbine will be equipped with DLN combustors, and an inlet air filtration system with evaporative coolers. The unit shall include the Speedtronic™ Mark VI automated gas turbine control system, and will have dual-fuel capability. [Application; Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one heat recovery steam generator (HRSG) with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator. The HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 565 MMBtu per hour (HHV).

The duct burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NO_X/MMBtu. [Application; Design]

CONTROL TECHNOLOGY

5. DLN Combustion: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NO_X emissions from the gas turbine when firing natural gas. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.
6. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from the gas turbine when firing distillate fuel oil. Prior to the initial emissions performance tests required for the gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.
7. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the gas turbine when firing either natural gas or distillate fuel oil. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions.

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

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

PERFORMANCE RESTRICTIONS

8. Permitted Capacity – Gas Turbine: The maximum heat input rate to the gas turbine is 1,787 MMBtu per hour when firing natural gas and 1,967 MMBtu per hour when firing distillate fuel oil (based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]
9. Permitted Capacity - HRSG Duct Burners: The total maximum heat input rate to the duct burners for the HRSG is 560 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]
10. Hours of Operation: The gas turbine may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified in separate conditions. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]
11. Authorized Fuels: The gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, the gas turbine may fire ultra low sulfur distillate fuel oil containing no more than 0.0015% sulfur by weight. The

gas turbine shall fire no more than 500 hours of fuel oil, regardless of mode, during any calendar year. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

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

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

    b. *Pseudo Simple Cycle Operation*: The gas turbine/HRSG system may operate in a pseudo simple cycle mode where steam from the HRSG bypasses the steam turbine electrical generator and is dumped directly to the condenser. This is not considered a separate mode of operation with respect to emission limits (i.e. emission limits of combined cycle operation still apply).

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

    d. Duct Firing: When firing natural gas, the HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power.

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

EMISSIONS STANDARDS

13. Emission Standards: Emissions from the turbine/HRSG system shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X[b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10}[c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia[e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, established in Condition No. 11 of this section, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be determined by the requirements in Condition No. 30 of this section. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, established in Condition No. 11 this section, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 30 of this section.

e. The SCR system shall be designed and operated for an ammonia slip limit of no more than 5 ppmvd corrected to 15% O_2 based on the average of three test runs.

f. The mass emission rate standards are based on a turbine inlet condition of 59°F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted from actual test conditions in accordance with the performance curves and/or equations on file with the Department.

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

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 13 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

14. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the gas turbine, HRSG, 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 for minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

15. Definitions

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions.
    [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose.
    [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner.
    [Rule 62-210.200(159), F.A.C.]

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

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

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

    a. *Steam Turbine/HRSG System Cold Startup:* For cold startup of the steam turbine/HRSG system, excess emissions from the gas turbine/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the steam turbine/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, the gas turbine/HRSG system is brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue}

b. *Steam Turbine/HRSG System Warm Startup:* For warm startup of the steam turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. A "warm startup of the steam turbine/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

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

d. *Fuel Switching:* Excess emissions due to oil-to-gas fuel switching shall not exceed 1 hour in any 24-hour period.

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

20. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

21. 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 • This is an EPA conditional test method. • The minimum detection limit shall be 1 ppm.
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources • 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.
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. 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]

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

23. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), the gas turbine shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO and NO_x standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

24. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour CO and NOX emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. The Department also reserves the right to use data from the continuous monitoring record and from annual RATA tests to determine compliance with the short term CO and NO_X limits for each method of operation given in Condition 12 above. [Rule 62-212.400 (BACT), F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

25. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

    b. *NO_X Monitor:* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation}

d. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 18 and 20 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

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

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

RECORDS AND REPORTS

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

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

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

    a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions.

    b. Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to the Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the 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. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

32. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    b. *SIP Quarterly Report*: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NOx emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

    c. *NSPS Semi-Annual Reports*: For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any operating hour in which the CEMS 4-hr rolling average NOx concentration exceeds the NSPS NOx emissions standard identified in Appendix GG; and any monitoring period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority. This also includes reporting any periods of excess emissions as applicable and defined by NSPS Subpart KKKK when the rule is finalized.

{Note: If there are no periods of excess emissions as defined in NSPS Subparts GG, Da, or KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7, and 60.332(j)(1)]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for the fuel oil storage tank for use in the Annual Operating Report. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

C. Fuel Oil Storage Tank (EU 002)

ID	Emission Unit Description
002	One distillate fuel oil storage tank for Unit 1 combustion turbine (approximately 1 million gallons).

NSPS APPLICABILITY

1. NSPS Subpart Kb Applicability: Subpart Kb does not apply to storage vessels with a capacity greater than or equal to 151 cubic meters storing a liquid with a maximum true vapor pressure less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 cubic meters but less than 151 cubic meters storing a liquid with a maximum true vapor pressure less than 15.0 kPa. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 5.2 kPa and greater than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb, except for the monitoring requirements. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa, are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. The fuel oil storage tank (EU 002) has a capacity greater than 151 cubic meters and the vapor pressure of the ultra low sulfur fuel oil is less than 3.5 kPa, therefore NSPS Kb, including the monitoring requirements, does not apply to this unit.
[40 CFR 60.110b(a) and (b), and 60.116b(c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one 990,000 gallon distillate fuel oil storage tank designed to provide ultra low sulfur fuel oil to the Unit 1 gas turbine. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

PERFORMANCE REQUIREMENTS

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

NOTIFICATION, REPORTING, AND RECORDS

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

C. Cooling Tower (EU 003)

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

ID	Emission Unit Description
003	One 8-cell mechanical draft cooling tower.

EQUIPMENT

1. Cooling Tower: The permittee is authorized to install one 8-cell mechanical draft cooling tower with the following nominal design characteristics: a circulating water flow rate of 111,130 gpm; a design air flow rate of 1,000,000 acfm per cell; drift eliminators; a drift rate of no more than 0.0005 percent of the circulating water flow. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 10 tons of PM per year and less than 2 tons of PM_{10} per year. Actual emissions are expected to be lower than these rates.}.

D. Safe Shutdown Generator (EU 004)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
004	One safe shutdown generator (approximately 765 hp).

NESHAPS APPLICABILITY

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

EQUIPMENT SPECIFICATIONS

1. Safe Shutdown Generator: The permittee is authorized to install, operate, and maintain one safe shutdown generator. The safe shutdown generator may operate when the transmission connection is lost and the plant shuts down, and during occasional testing to ensure operability. The safe shutdown generator will fire ULS fuel oil. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

2. Hours of Operation: The safe shutdown generator may operate 200 hours per year. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

{Permitting Note: Emissions from the safe shutdown generator are included in the potential to emit for the project.}

E. Diesel Fire Pump (EU 005)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
005	One diesel engine fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank.

NESHAPS APPLICABILITY

NESHAPS Subpart ZZZZ Applicability: The facility is not a "Major Source" of hazardous air pollutants (HAPs), therefore the generator is not subject to Subpart ZZZZ.

EQUIPMENT SPECIFICATIONS

1. Fire Pump: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) with associated 500 gallon fuel oil storage tank. The diesel engine fire pump will fire ULS fuel oil. [Application; Design]

EMISSIONS AND PERFORMANCE REQUIREMENTS

Hours of Operation: The fire pump may operate 200 hours per year.
[Applicant Request; Rule 62-210.200(PTE), F.A.C.

{Permitting Note: The fire pump is considered emergency equipment, therefore exempt from permitting, however its emissions are included in the potential to emit for the project.}

SECTION IV. APPENDICES

CONTENTS

NSPS SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

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

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

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

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O_2	lb/hr[f]	ppmvd @ 15% O_2
CO[a]	Oil	Combustion Turbine (CT)	8.0	37.1	8.0, 24-hr
	Gas	CT, Normal	4.1	16.4	
		CT & Duct Burner (DB)	7.6	39.7	
	Oil/Gas	All Modes	NA	NA	6.0, 12-month
NO_X[b]	Oil	CT	8.0	61.0	8.0, 24-hr
	Gas	CT, Normal	2.0	13.2	2.0, 24-hr
		CT & DB	2.0	17.1	
PM/PM_{10}[c]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
			Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	All Modes	0.0015% sulfur fuel oil, 2 gr S/100 SCF of gas		
Ammonia[e]	Oil/Gas	CT, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour and 12-month CO standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 10 tests associated with the certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and basic duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart GG or certification and quality assurance of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2.

c. The fuel sulfur specifications, combined with the efficient combustion design and operation of the gas turbine represents (BACT) for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur requirements. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications, effectively limit the potential emissions of SAM and SO2 from the gas turbine and represent BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur as detailed in the draft permit.

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

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

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

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

Recommended By:	Approved By:
Trina L. Vielhauer, Chief Bureau of Air Regulation	Michael G. Cooke, Director Division of Air Resources Management
Date	Date

NSPS SUBPART Da REQUIREMENTS FOR DUCT BURNERS

The HRSG duct burners are part of the Unit 1 gas turbine/HRSG system, which are regulated as Emissions Unit 001.

§ 60.40a Applicability and Designation of Affected Facility.

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

§ 60.41a Definitions.

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

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

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

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

"Gaseous fuel" means any fuel derived from coal or petroleum that is present as a gas at standard conditions and includes, but is not limited to, refinery fuel gas, process gas, and coke-oven gas.

"Natural gas" means: (1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) Liquid petroleum gas, as defined by the American Society of Testing and Materials (ASTM) Standard Specification for Liquid Petroleum Gases D1835-87, 91, 97, or 03a (incorporated by reference, see 60.17).

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

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

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

§ 60.44a Standard for Nitrogen Oxides.

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

§ 60.48a Compliance Provisions.

The HRSG duct burner systems are restricted to the exclusive firing of natural gas. The maximum expected emissions of particulate matter and sulfur dioxide are much lower than the limits established by this subpart for a HRSG duct burner system firing solid, liquid, or other gaseous fuels.

In accordance with § 60.48a(k)(1), compliance with the nitrogen oxides (NO_X) standard specified in § 60.44a(d)(1) for duct burners used in combined cycle systems shall be determined as follows:

$$E = [(Csg \times Qsg) - (Cte \times Qte)]/(Osg \times h) \qquad \text{(Equation 1)}$$

Where:

E	=	Emission rate of NOx from the duct burner, ng/J (lb/Mwh) gross output
Csg	=	Average hourly concentration of NO_X exiting the steam generating unit, ng/ dscm (lb/dscf)
Cte	=	Average hourly concentration of NO_X in the turbine exhaust upstream from duct burner, ng/dscm (lb/dscf)
Qsg	=	Average hourly volumetric flow rate of exhaust gas from steam generating unit, dscm/hr (dscf/hr)
Qte	=	Average hourly volumetric flow rate of exhaust gas from combustion turbine, dscm/hr (dscf/hr)
Osg	=	Average hourly gross energy output from steam generating unit, J (Mwh)
h	=	Average hourly fraction of the total heat input to the steam generating unit de-rived from the combustion of fuel in the affected duct burner

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

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

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

In accordance with § 60.48a(k)(3), when an affected duct burner steam generating unit utilizes a common steam turbine with one or more affected duct burner steam generating units, the owner or operator shall either:

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

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

§ 60.49a Emission Monitoring.

In accordance with § 60.49a(o), the owner or operator of a duct burner, as described in § 60.41a, which is subject to the NO_X standards of § 60.44a(a)(1) or (d)(1) is not required to install or operate a continuous emissions monitoring system to measure NO_X emissions; a wattmeter to measure gross electrical output; meters to measure steam flow, temperature, and pressure; and a continuous flow monitoring system to measure the flow of exhaust gases discharged to the atmosphere.

§ 60.50a Compliance Determination Procedures and Methods.

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

§ 60.51a Reporting requirements.

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

GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

    a. A description of and cause of non-compliance; and

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

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

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

Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

13. This permit also constitutes:

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

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

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

§ 60.330 Applicability and Designation of Affected Facility.

Unit 1 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG.

§ 60.331 Definitions.

The following applicable terms are defined by this subpart:

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

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

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

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

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

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

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

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

§ 60.332 Standard for Nitrogen Oxides.

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

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

Where:

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

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

F = NO_X emission allowance for fuel-bound nitrogen as de-fined in paragraph (a)(4) of this section.

§ 60.332(a)(3) defines an allowable NO_X contribution based on the fuel bound nitrogen content, F. However, natural gas and distillate oil contain negligible concentrations of fuel bound nitrogen. Therefore, "F" shall be assumed to be 0. Based on the manufacturer's data and compressor inlet conditions of 59° F and 60% relative humidity, the heat rate for gas firing is 9,355 Btu/KW-h at peak load and for oil firing is 10,120 Btu/KW-h at peak load. This results in "Y" values of 9.9 for gas firing and 10.7 for oil firing. The equivalent NSPS NO_X emission standards are 110/101 ppmvd at 15% oxygen for gas/oil firing. Compliance with the NOx standards of the PSD permit ensure compliance with the applicable NSPS standards. The permittee shall make the correction when required by the Department or Administrator.

§ 60.333 Standard for Sulfur Dioxide

In accordance with § 60.333(b), fuel fired in the gas turbines shall contain no more than 0.8% sulfur by weight. The conditions of the PSD permit limit allowable fuels to natural gas (≤ 2.0 grains of sulfur per 100 standard cubic feet of natural gas) and distillate oil (≤ 0.0015% sulfur by weight). These conditions ensure compliance with the NSPS standard for sulfur dioxide.

§ 60.334 Monitoring of Operations.

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

For the purpose of reports required under § 60.7(c), periods of excess emissions that shall be reported are: any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the NSPS standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8% sulfur by weight (for sulfur dioxide emissions). The permittee shall submit a semiannual report of emissions in excess of the NSPS standards.

§ 60.335 Test Methods and Procedures.

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

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

Where:

NOx	=	Emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent
NOxo	=	Observed NOx concentration, ppm by volume
Pr	=	Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg
Po	=	Observed combustor inlet absolute pressure at test, mm Hg
Ho	=	Observed humidity of ambient air, g H_2O/g air
e	=	Transcendental constant, 2.718
Ta	=	Ambient temperature, °K

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

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

STANDARD CONDITIONS

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

EMISSIONS AND CONTROLS

1. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]
2. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]
3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]
4. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]
5. Excess Emissions - Notification: In case of excess emissions resulting from malfunctions, the permitee shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]
6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]
7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]
8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

11. Operating Rate During Testing: Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impractical to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. [Rule 62-297.310(2), F.A.C.]

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

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

    b. Minimum Sample Volume. Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

    a. Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

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

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

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

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

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

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

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

RECORDS AND REPORTS

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

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

Jeb Bush
Governor

Department of Environmental Protection

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

Colleen M. Castille
Secretary

P.E. Certification Statement

Permittee: **DEP File No.** 1110121-001-AC (PSD-FL-353, PA 05-48)

Treasure Coast Energy Center
St. Lucie County

Project type:

Project is construction of a nominal 300-megawatt (MW) combined cycle power plant with a 170 MW GE7FA combustion turbine-electrical generator, a duct fired heat recovery steam generator, a nominal 130 MW steam turbine-electrical generator, a 170-foot stack, a mechanical draft cooling tower, a 990,000 gallon fuel oil tank and ancillary equipment. The unit will operate a maximum of 8,760 hours per year of which 500 hours per year may be on ultra low sulfur fuel oil (0.0015 percent sulfur).

The proposed continuous (24-hour) BACT NO_X limits are 2 ppmvd @15% O_2 when operating on natural gas and 8 ppmvd @15% O_2 when burning fuel oil. Other pollutants, including particulate matter (PM/PM_{10}), carbon monoxide, volatile organic compounds, sulfur dioxide, and sulfuric acid mist will be controlled by good combustion and use of clean fuels.

Projected impacts from the proposed project are all less than the applicable significant impact limits (SILs) corresponding to the nearby Class II areas and the Class I Chassahowitzka National Wildlife Area. The project will not cause or contribute to a violation of any National Ambient Air Quality Standard or Increment. The Fish and Wildlife Service had no adverse comments regarding this project.

The project is subject to Sections 403.501-518, F.S., Florida Power Plant Siting Act.

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

A A Linero 10/25/05

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

Department of Environmental Protection
Bureau of Air Regulation
Permitting South Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

aaL 10/25

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
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A A Linero 10/25/05

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

Department of Environmental Protection
Bureau of Air Regulation
Permitting South Section
111 South Magnolia Drive, Suite 4 aal 10/25
Tallahassee, Florida 32301
Phone (850) 921-9523
Fax (850) 922-6979

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1. Article Addressed to:

Mr. Roger A. Fontes, General Manager and CEO
Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

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X Khuile Jones ☐ Agent ☐ Addressee

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Florida Municipal Power Agency
8553 Commodity Circle
Orlando, Florida 32819

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