Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

November 2, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Robert G. Moore, V.P. Power Generation/Transmission
Gulf Power Company
Lansing Smith Electric Generating Plant
One Energy Place
Pensacola, Florida 32520-0100

Re: DEP File No. PA 99-40 (PSD-FL-269)
Lansing Smith Unit 3
566 Megawatt Combined Cycle Unit

Dear Mr. Moore:

Enclosed is one copy of the Draft Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the Lansing Smith Unit 3 to be located at the existing Lansing Smith facility in Southport, Bay County. The Department's Intent to Issue PSD Permit and the "PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT" are also included.

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

Please submit any written comments you wish to have considered concerning the Department's proposed action to A. A. Linero, P.E., Administrator, New Source Review Section at the above letterhead address. If you have any questions, please call Michael P. Halpin, P.E. at 850/921-9530.

Sincerely,

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

CHF/mph

Enclosures

In the Matter of an
Application for Permit by:

Mr. Robert G. Moore, V.P. Power Gen./ Transmission
Gulf Power Company
One Energy Place
Pensacola, Florida 32520
_____________________________________/

Facility I.D. No. 0050014
DEP File No. PA 99-40 (PSD-FL-269)
566 MW Combined Cycle Power Plant
Lansing Smith Facility
Bay County

INTENT TO ISSUE PSD PERMIT

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

The applicant, Gulf Power, applied on May 27, 1999 to the Department for a PSD permit to construct a 566 megawatt combined-cycle electrical power generating plant consisting of: two nominal 170 MW "F" class combustion turbine-electrical generators; two supplementally fired heat recovery steam generators capable of raising sufficient steam to generate another 200 MW from a single steam-electrical generator; a mechanical draft cooling tower; two 121 foot stacks; and ancillary equipment. The project will be located at the Lansing Smith facility, located at 4300 Highway 2300, Southport, Bay County.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, and 62-212. The above actions are not exempt from permitting procedures. The Department has determined that a PSD permit and a determination of Best Available Control Technology for the control of carbon monoxide, sulfur dioxide, sulfuric acid mist, particulate matter, and volatile organic compounds, is required to conduct the work.

The Department intends to issue this PSD permit based on the belief that reasonable assurances have been provided to indicate that operation of these emission units will not adversely impact air quality, and the emission units will comply with all appropriate provisions of Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. and 40 CFR 52.21.

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

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

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

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).

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

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

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

C. H. Fancy, P.E., 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, Draft BACT Determination, and the DRAFT PSD permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 11-3-99 to the person(s) listed:

Mr. Robert G. Moore, Gulf Power *
Mr. G. Dwain Waters, Gulf Power
Mr. Tom Davis, P.E., ECT
Mr. Ed Middleswart, DEP-NWD
Mr. John Bunyak, NPS
Mr. Gregg Worley, EPA
Mr. Hamilton S. Oven, DEP-Siting
Chair, Bay County

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.

11-3-99
(Clerk) (Date)

Z 031 391 996

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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

Sent to Robert Moore	
Street & Number Gulf Power Co	
Post Office, State, & ZIP Code Pensacola Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date PSD-Fl-269 PA 99-40	11-3-99

PS Form **3800**, April 1995

SENDER:

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

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

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

Consult postmaster for fee

3. Article Addressed to:
Robert G. Moore, VP
Gulf Power Co
One Energy Place
Pensacola, Fl
32520-0100

4a. Article Number
Z 031 391 996

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

7. Date of Delivery

5. Received By: *(Print Name)*
RICHARD E ANDREWS

6. Signature: *(Addressee or Agent)*
X Richard E Andrews

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

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

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

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PA 99-40
PSD-FL-269
Gulf Power Lansing Smith Facility
566 Megawatt Combined Cycle Unit No. 3
Bay County

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to Gulf Power Company. The permit is to install a gas-fired combined cycle unit at the Lansing Smith Plant in Southport, Bay County. A Best Available Control Technology (BACT) determination was required pursuant to Rule 62-212.400, F.A.C. and 40 CFR52.21 for emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC) sulfur dioxide (SO_2) and sulfuric acid mist (SAM). The applicant's name and address are Gulf Power Company, One Energy Place, Pensacola, Florida 32520.

The unit consists of two nominal 170 megawatt General Electric PG7241FA gas-fired combustion turbine-generators with duct-fired heat recovery steam generators (HRSGs) that will raise sufficient steam to produce approximately another 200 MW via a steam-driven electrical generator. The gas turbines and duct burners will fire only natural gas and are not being permitted for operation in simple cycle (non-steam mode). The project also includes: a cooling tower; small heaters to heat the natural gas prior to use; and two relatively short stacks.

The applicant is proposing concurrent installation of low NO_X burners on existing Smith Unit 1, as well as a facility-wide NO_X cap, thereby ensuring no net increase in NO_X and eliminating the requirement for a BACT determination for this pollutant. Nitrogen oxides (NO_X) emissions will be controlled by Dry Low NO_X (DLN-2.6) combustors capable of achieving emissions of 10.6 parts per million (ppm) by volume at 15 percent oxygen while firing duct burners. Emissions of carbon monoxide (CO) will be controlled to 16 ppm, while emissions of volatile organic compounds (VOC) will be less than 4 ppm. Emissions of sulfur dioxide (SO_2), sulfuric acid mist (SAM), and particulate matter (PM/PM_{10}) will be very low because of the inherently clean pipeline quality natural gas. The unit will be permitted with steam augmentation for up to 1000 hours per year, during which time NO_X emissions will be up to 13.6 ppm, CO emissions up to 23 ppm and VOC emissions up to 6 ppm.

The following maximum potential annual emissions (in tons per year) summarize the maximum increase in regulated air pollutants as a result of this project. NO_X emission increases at the facility are shown as zero due to a facility-wide NO_X cap of 6666 TPY, which is based upon past actual emissions.

Pollutants	Unit 3 Maximum Emissions	Maximum Facility Increase
PM/PM_{10}	253	253
SAM	12	12
SO_2	105	105
NO_X	757	0
VOC	93	93
CO	701	701

Absent this project and the proposed NO_X emissions cap, the permitted NO_X emissions from the plant (including mandated Phase II reductions) are over 7,342 TPY.

An air quality impact analysis was conducted. Emissions from the facility will not contribute to or cause a violation of any state or federal ambient air quality standards. The maximum predicted PM_{10} PSD Class II increments consumed by all sources in the area, including this project, will be as follows:

Avg. Time	Allowable Increment ($\mu g/m^3$)	Increment Consumed ($\mu g/m^3$)	Percent Consumed
24-hour	30	11	37
Annual	17	1	6

The project by itself has no significant impact on the PSD Class I Bradwell Bay National Wilderness Area.

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

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

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).

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

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

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

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

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

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

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

Florida Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32501-5794
Telephone: 850/595-8300
Fax: 850/595-4417

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

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

Gulf Power Company

Lansing Smith Power Plant
566 Megawatt Combined Cycle Project

Bay County

PA 99-40 and PSD-FL-269

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

November 2, 1999

TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Gulf Power Company
Lansing Smith Plant
4300 Highway 2300
Southport, Florida 32409

Authorized Representative: Robert G. Moore, VP Power Generation/Transmission

1.2 Reviewing and Process Schedule

06-07-99:	Date of Receipt of Application
10-06-99:	Completeness Date
11-01-99:	Intent Issued

2. FACILITY INFORMATION

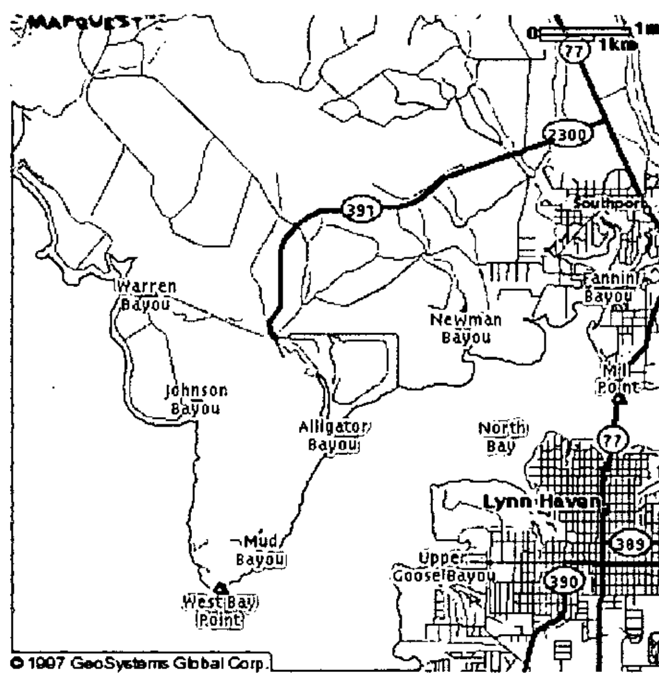
2.1 Facility Location

Refer to Figures A1 and A2. The Smith Plant is located in Central Bay County, at the end of County Road 2300, which connects to State Road 77. This site is approximately 103 kilometers from Bradwell Bay National Wilderness Area, a Class I PSD Area.

The UTM coordinates of this facility are Zone 16; 625.03 km E; 3,349.08 km N.

FIGURE A1

FIGURE A2



2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

The Gulf Power Smith Plant currently generates electric power from two oil or coal-fired steam units and one oil-fired combustion turbine with a combined (facility) summer net generating capacity of 386 megawatts (MW).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a major facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications at the facility resulting in emissions increases greater than: 100 TPY of CO, 40 TPY of NO_X, VOC or SO_2, 25/15 TPY of PM/PM_{10}, or 7 TPY of SAM requires review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C. The present (Smith Unit 3) addition includes concurrent installation of low NO_X burners on Smith Unit 1 resulting in net emissions decreases or less-than-significant increases in this PSD pollutant. Therefore, the addition is subject to PSD for CO, VOCs, PM/PM_{10}, SO_2 and Sulfuric Acid Mist (SAM).

The facility is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 TPY.

3. PROJECT DESCRIPTION

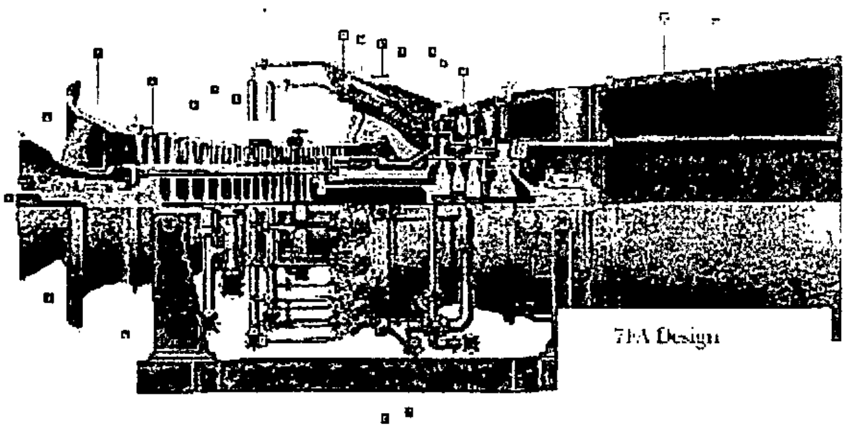
This permit addresses the following emissions units:

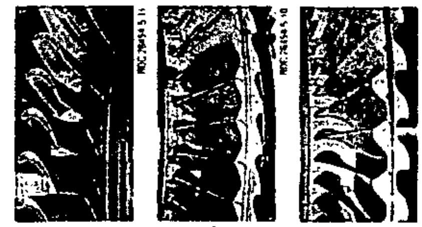
Emission Unit No.	System	Emission Unit Description
004	Power Generation	Combustion Turbine No.1 with duct burner (part of Combined Cycle Unit 3)
005	Power Generation	Combustion Turbine No.2 with duct burner (part of Combined Cycle Unit 3)
006	Water Cooling	Mech. Draft (Saltwater) Cooling Tower

Gulf Power proposes to install a natural gas-fired combined cycle unit that will consist of two (2) nominal 170 MW (@ 59°F) combustion turbine-generators and two heat recovery steam generators (HRSG) with duct burners. The HRSGs will raise steam to power a steam turbine thus producing approximately another 200 MW of electricity or 574 MW for the full combined cycle unit with duct burners and steam power augmentation (566 nominal MW).

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

FIGURE B

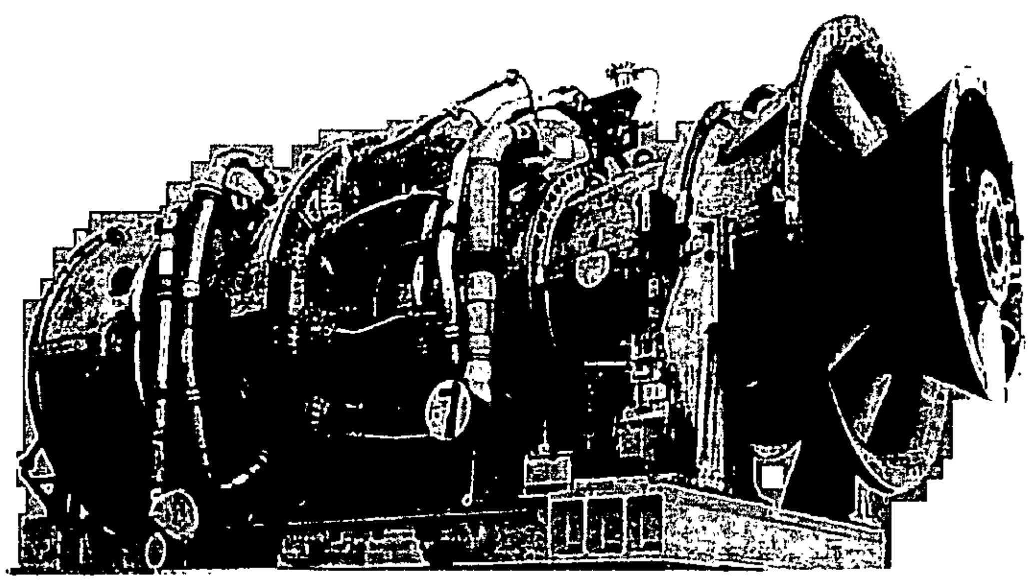




15. Impingement Cooled Combustor Transition Piece – separate perforated sleeve around transition piece causes compressor discharge air to impinge on and effectively cool the transition piece.

Each turbine will be equipped with Dry Low NO_x (DLN-2.6) combustors for the control of NO_X emissions to 9 ppmvd at 15% O_2 from 50% load up to 100% load conditions during normal operations. Each turbine will have a nominal heat input of 1,751 million BTUs per hour, lower heating value (MMBtu/hr, LHV) at 59°F. The HRSGs will be supplementally fired by 275 MMBtu/hr duct burners. The units will fire only pipeline quality natural gas.

FIGURE C



The project includes a mechanical draft cooling tower to reduce the temperature of the blowdown water discharged into the existing discharge tunnel. A separate 121-foot stack will also be installed for each combustion turbine.

No emission increase will occur for nitrogen oxides (NO_X), however increases will occur for sulfur dioxide (SO_2), sulfuric acid mist (H_2SO_4 mist or SAM), particulate matter (PM/PM_{10}), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC). Emission increases these pollutants will be greater than the significant emission levels per Table 62-212.400-2, F.A.C. Therefore, review for the Prevention of Significant Deterioration (PSD) is required for these emissions. A complete description of the NO_X netting analysis is described in Sections 7.1 and 7.2.

4. PROCESS DESCRIPTION

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

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

Flame temperatures in a typical combustor section can reach 3600 degrees Fahrenheit (°F). Units such as the 7FA operate at lower <u>flame</u> temperatures, which minimizes NO_X formation. The hot combustion gases are then diluted with additional cool air and directed to the turbine section at temperatures of approximately 2400 °F. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator.

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

In combined cycle operation, the gas turbine drives an electric generator while the exhausted gases are used to raise steam in a heat recovery steam generator (HRSG). In this case, most of the steam is fed to a separate steam turbine that also drives an electrical generator. The main stack follows the HRSG and is required for combined cycle operation. In combined cycle mode, the thermal efficiency of the 7FA can exceed 56 percent. At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for a portion of the loss of output (which can be on the order of 20 MW compared to referenced temperatures), inlet foggers will be installed ahead of the combustion turbine inlet air intake duct. At an ambient temperature of 95°F, roughly 10 MW of power can be regained by using the foggers. Additional process information related to the combustor design, and control measures to minimize NO_X formation are given in the control technology section below.

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of Chapter 403, Florida Statutes, Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21.

This facility is located in Bay County, an area designated as attainment for all criteria pollutants in accordance with Rule 62-204.360, F.A.C. The proposed project is subject to review under Rule 62-212.400., F.A.C., Prevention of Significant Deterioration (PSD) for VOC, CO, SO_2 and PM/PM_{10}. Because the potential emissions for NO_X decrease or remain the same with the concurrent installation of low NO_X burners on Smith Unit 1, and emissions do not exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C., PSD review for this regulated pollutant is not applicable.

This evaluation consists of a review of the control technology for PM/PM_{10}, VOC, CO, SAM and SO_2. Additionally, NO_X will be reviewed to insure that it is reasonably consistent with similar installations and to evaluate the proposed facility-wide cap. An analysis of the air quality impact from proposed project is required to insure that there are no exceedances of the National or State Ambient Air Quality Standards.

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

5.1 State Regulations

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

5.2 Federal Rules

40 CFR 52.21	Prevention of Significant Deterioration
40 CFR 60	NSPS Subparts GG and Da
40 CFR 60	Applicable sections of Subpart A, General Requirements
40 CFR 72	Acid Rain Permits (applicable sections)
40 CFR 73	Allowances (applicable sections)
40 CFR 75	Monitoring (applicable sections including applicable appendices)
40 CFR 77	Acid Rain Program-Excess Emissions (future applicable requirements)

6. AIR POLLUTION CONTROL TECHNOLOGY

6.1 Applicant Control Technology Proposal

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
Particulate Matter	Pipeline Natural Gas Combustion Controls	10% Opacity
Volatile Organic Compounds	As Above	3 ppmvd (CTs) - gas 4 ppmvd (w/duct burners)- gas 6 ppmvd (w/DB & stm. aug.) - gas
Carbon Monoxide	As Above	13 ppmvd (CTs) - gas 16 ppmvd (w/duct burners)- gas 23 ppmvd (w/DB & stm. aug.) - gas
Sulfur Dioxide	As Above	2 gr/100 scf - gas
Nitrogen Oxides	Dry Low NO_x Combustors (CTs) Dry Low NO_x Burners (Unit 1 Boiler)	9 ppmvd (CTs) @ 15% O_2 gas ** 10.6 ppmvd (w/DB) @ 15% O_2 ** 13.6 ppmvd (w/DB & stm. aug.) **

** NOTE: The proposed NO_X emission rates listed are for informational purposes only.

According to the application, the new combined cycle unit will emit approximately 757 tons per year (TPY) of NO_X, 701 TPY of CO, 93 TPY of VOC, 105 TPY of SO_2, 12 TPY of sulfuric acid mist, and 253 TPY of PM/PM_{10}. The cooling tower will emit about 79.5 TPY of PM/PM_{10}. When low NO_X burners are installed on the existing unit 1, there will be no net increase in facility-wide NO_X emissions (facility-wide cap proposed). The combined use of duct burners and steam augmentation is proposed to be limited to 1000 hrs. /year.

6.2 Standards of Performance for New Stationary Sources

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

The 275 MMBtu duct burners required for supplementary gas-firing of the HRSG's are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The NO_X emissions estimated by Gulf of 0.07 pounds of NO_X per million Btu heat <u>input</u> (lb. NO_X/MMBtu) are less than half of the key historically applicable NSPS requirement of 0.20 lb. NO_X/MMBtu. Additionally, this is below the revised Subpart Da <u>output</u>-based limit of 1.6 lb NO_X/MW-hr promulgated on September 3, 1998.

6.3 Determinations by EPA and States

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

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

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

6.4 Review of Combustion Turbine Control Technologies

A complete discussion of control options was required for a majority of pollutants except NO_X, because the project is subject to a Best Available Control Technology Determination for those pollutants. However the applicant discussed the technology to be employed for all pollutants including NO_X in order to comply with the New Source Performance Standards and the requested limits. The Department has included other information typically included in a complete BACT determination for comparison purposes.

6.4.1 Nitrogen Oxides Formation

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

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

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

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. It is not important for the Gulf project because natural gas will be the only fuel used.

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

6.4.2 NO_x Control Techniques

Wet Injection

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

Combustion Controls

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

The above principle is depicted in attached "Figure 1" for a General Electric can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in attached "Figure 1") wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the Gulf project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in attached Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at Jacksonville Electric Authority's Kennedy Station.

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

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppm of CO. Simplified cross sectional views of the totally premixed DLN-2.6 combustor to be installed at the Gulf project are shown in attached Figure 3.

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

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

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

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from attached Figure 4 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

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

With the concurrent installation of low NO_x burners on the existing Smith Unit 1, there will be no net increase in NO_X emissions. See Sections 7.1 and 7.2 for a complete description of the NO_X netting analysis.

Selective Catalytic Combustion

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

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now available, however, and catalyst formulation improvements have proven effective in resisting performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, versus 8 to 10 years with natural gas. Excessive ammonia use tends to increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

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

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

Selective Non-Catalytic Combustion

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

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

Emerging Technologies: SCONOX™ and XONON™

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

The first technology is called $SCONO_X$™ and is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires a dilute hydrogen reducing gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[2] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at U.S. Generating's La Paloma Plant near Bakersfield.[3] The overall project includes several more 250 MW blocks with SCR for control.[4] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle General Electric LM2500 turbine (without duct burners) equipped with the patented SCONOx™ system.

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

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

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

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

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

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

6.5 Control Technology Determination

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

Emission Unit	NO_X	CO BACT	SO_2/SAM BACT	VOC BACT	PM/Visibility (% Opacity)	Technology and Comments
C.T.'s : Standard Duct Burners	9 ppmvd 10.6 ppmvd	13 ppmvd 16 ppmvd	2 gr/100 scf natural gas	3 ppmvd 4 ppmvd	10 - gas 10 - gas	Dry Low NO_x Combustors Natural Gas, Good Combustion
Steam power Augmentation	13.6 ppmvd	23 ppmvd	2 gr/100 scf natural gas	6 ppmvd	10 - gas	Unit limited to 1000 hours per year of operation
Cooling Tower					18.2 lb/hr	Annual Inspection / O&M Plan

6.6 Compliance Procedures

Pollutant	Compliance Procedure
Visible Emissions / P.M.	Method 9 (initial tests only)
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Initial and Annual Method 10 (can use RATA if at capacity)
NO_X (annual facility-wide cap)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (NSPS initial performance)	Method 20 (can use RATA if at capacity)

6.7 Excess Emissions

Allowable Excess Emissions: Pursuant to Rule 62-210.200 F.A.C., excess emissions are allowable under the following scenarios: Valid hourly emission rates shall not included periods of startup (~240 minutes), shutdown, or malfunction as defined in Rule 62-210.200

F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in permit Specific Condition 27. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request]

7. SOURCE IMPACT ANALYSIS

7.1 Emission Limitations

The applicant's proposed annual emissions are summarized in the Table below (Section 7.2) and form the basis of the source impact review.

Operation of the existing units 1 and 2 will be limited as a result of a facility-wide NO_X emissions cap requested by Gulf. The existing units are currently included within a company-wide NO_X averaging plan, which allows for Unit 1 to operate at a NO_X emission rate (0.62 lb./MMBtu) which is higher than the promulgated Phase II limit. Without the emission cap, but incorporating Phase II NO_X emission limits of 0.40 lb./MMBtu on each existing emission unit (001 and 002), emissions could be as high as 3407 TPY (Unit 1) and 3935 (Unit 2) for a total of 7342 TPY. Additionally, there are uncontrolled emissions from the small diesel-fired peaking unit EU-003 (reported at 94 tons in 1998). Therefore, the proposed facility-wide cap of 6666 TPY is more stringent than the Phase II limits (which are more stringent than the averaging plan) even prior to including the new combined cycle unit within the cap. Lastly, the Department believes that it is reasonable to expect that Smith Unit 1 NO_X emissions will be reduced by 20-25% with the installation of low NO_X burners, which alone could provide room for the operation of the new combined cycle unit.

7.2 NO_X Facility-wide Emissions Summary

The historical NO_X emissions are shown below, forming a basis for the facility-wide NO_X cap (with concurrent installation of low NO_X burners on existing Unit 1 (EU-001)). Data from the diesel-fired peaking unit (EU-003) is intentionally ignored in this tabulation due to its relative insignificance, but the emission unit is included within the facility-wide cap.

Two-year Historical NO_X Emissions (TPY)

Consecutive 2 Year Period	EU-001 Past Actual Emissions	EU-002 Past Actual Emissions	EU-001 + EU-002 Past Actual Emissions	Representative of Typical operation
1997-1998	3359	2395	5754	NO
1996-1997	3533	2707	6240	NO
1995-1996	3881	2785	6666	YES
1994-1995	3344	3316	6661	YES
1993-1994	3148	3458	6606	(see note below)
FDEP Allowable			6666	**FAC-wide cap.**

Note: Data based upon CEMS except for 1993 and 1994, which is based upon AOR AP-42 Factors.

7.3 Air Quality Analysis

7.3.1 Introduction

The proposed project will increase emissions of four pollutants at levels in excess of PSD significant amounts: PM/PM_{10}, CO, SO_2, VOC and SAM. PM_{10} and SO_2 are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO and VOC are criteria pollutants and have only AAQS and significant impact levels defined for them. Emission of VOCs are related to the formation of ozone and are not modeled for individual stationary sources. The VOC emissions increase is less than the *de minimis* monitoring level of 100 TPY; therefore, no air quality analysis is required for VOC. PM is a criteria pollutant, but has no AAQS or PSD increments defined for it; therefore, no air quality impact analysis was required for it either. Instead, the BACT requirement will establish the PM emission limits for this project. SAM is a non-criteria pollutant. There are no applicable PSD increments or AAQS for SAM. Instead, the BACT requirement will establish the SAM emission limit for this project. Due to the distance of the source from the PSD Class I Bradwell Bay National Wilderness Area (BBNWA), plus the type and amount of emissions from the source, no PSD Class I analyses were required for this project.

A review of the applicant's initial CO and SO_2 air quality impact analyses for this project showed no predicted significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. However, PM_{10} impacts were predicted to be above one of the applicable PM_{10} significant impact levels thus requiring further applicable AAQS and PSD increment impact analyses for this pollutant. Based on the preceding discussion the air quality analyses required by the PSD regulations for this project are the following:

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

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

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

The EPA-approved SCREEN3 (screening model) and Industrial Source Complex Short-Term (ISCST3) dispersion models were used to evaluate the pollutant emissions from the proposed project. These models determine ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area, and volume sources. They incorporate elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition The ISCST3 model allows for the separation of sources, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA recommended regulatory options. Direction-specific downwash parameters were used for all sources for which downwash was considered. The stacks associated with this project all satisfy the good engineering practice (GEP) stack height criteria.

Meteorological data used in the ISCST3 model consisted of a concurrent five consecutive year period of hourly surface weather observations and twice-daily upper air soundings recommended by the department. Surface data were collected from the National Weather Service (NWS) stations at Pensacola (1986-1987) and Apalachicola, Florida (1988-1990). Upper air data were collected at Apalachicola, Florida during the period 1986-1990. These NWS stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

7.2.3 Analysis of Existing Air Quality

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review unless otherwise exempted or satisfied. This requirement may be satisfied by using pre-existing representative monitoring data, if available. Also an exemption to the monitoring requirement shall be granted by rule if either of the following conditions is met: the maximum predicted air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimis ambient concentration; or the existing ambient concentrations are less than a pollutant-specific de minimis ambient concentration. If preconstruction ambient monitoring is exempted, determination of background concentrations for PSD-significant pollutants with established AAQS may still be necessary for use in any required AAQS analysis. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of sources not included in the modeling. No de minimis ambient concentration is provided for ozone. Instead, the net emissions increase of VOC is compared to a de minimis monitoring emission rate of 100 tons per year.

The table below shows maximum predicted pollutant concentrations from the project for comparison to these de minimis levels.

MAXIMUM PREDICTED PROJECT POLLUTANT CONCENTRATIONS FOR COMPARISON TO THE DE MINIMIS LEVELS				
Pollutant	**Averaging Time**	**Maximum Predicted Concentration ($\mu g/m^3$)**	**Impact Greater than De Minimis (Yes/No)**	**De Minimis Level ($\mu g/m^3$)**
SO_2	24-hr	2	No	13
PM_{10}	24-hr	13	Yes	10
CO	8-hr	39	No	575
VOC	Annual Emission Rate	93 TPY	No	100 TPY

As shown in the table SO_2, CO and VOC impacts are predicted to be less than the de minimis levels; therefore, preconstruction monitoring is not required for these pollutants. However, PM_{10} impacts from the project are predicted to be greater than the de minimis level; therefore, the applicant is not exempt from preconstruction monitoring for this pollutant. The applicant may instead satisfy the preconstruction monitoring requirement by using pre-existing representative data from a PM_{10} monitoring site in Panama City. Data from this monitor were also used to establish PM_{10} background concentrations for use in the required PM_{10} AAQS analysis. These values are 28 and 73 ug/m^3 for the annual and 24-hour averaging times, respectively.

7.2.4 Significant Impact Analysis

Initially, the applicant models the impacts of the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the SCREEN3 model was used to evaluate dispersion of emissions from the combined cycle facility for three loads (50%, 75% and 100%) and three seasonal operating conditions (summer, winter, and average). The worst case-operating mode identified by the SCREEN3 model for each pollutant and applicable averaging time was then used as input in the ISCST3 model. Over 500 receptors were placed along the facility's restricted property line and out to 10 km from the facility, which is located in a PSD Class II area. A mixed cartesian and polar grid receptor network was used. For each pollutant subject to PSD and also subject to PSD increment and/or AAQS analyses, this modeling compares maximum predicted pollutant concentrations due to the project with PSD significant impact levels to determine whether significant impacts due to the project were predicted in the vicinity of the facility. In the event that the maximum predicted pollutant concentrations of a proposed project are less than the appropriate significant impact levels, a full impact analysis for that pollutant is not required. A full impact analysis includes the predicted pollutant concentrations of emissions from the project along with emissions from other major sources located within the vicinity of the project and a background concentration to determine whether all applicable AAQS or PSD increments are predicted to be met for that pollutant. Consequently, a preliminary modeling analysis, which shows an insignificant impact, is accepted as the required air quality analysis (AAQS and PSD increments) for that pollutant and no further modeling for comparison to the AAQS and PSD increments is required. The tables below show the results of this modeling. The radius of significant impact, if any, for each pollutant and applicable pollutant averaging time is also shown in the tables below.

MAXIMUM PROJECT POLLUTANT CONCENTRATIONS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY					
Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Significant Impact Level (μg/m^3)	Significant Impact? (Yes/No)	Radius of Significant Impact (km)
SO_2	Annual	0.04	1	No	-
	24-hr	1	5	No	-
	3-hr	6	25	No	-
PM_{10}	Annual	0.5	1	No	-
	24-hr	13	5	Yes	2.4
CO	8-hr	14	500	No	-
	1-hr	36	2,000	No	-

The results of the significant impact modeling show that there are no significant impacts predicted due to SO_2 and CO emissions from this project; therefore, no further modeling for these pollutants was required. The maximum predicted air quality impacts due to PM_{10} emissions from the proposed project are greater than one of the PM_{10} significant impact levels. Therefore, the applicant was required to do full impact PM_{10} modeling within the applicable significant impact area. The significant impact area is based upon the predicted radius of significant impact.

7.2.5 AAQS Analysis

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

AMBIENT AIR QUALITY IMPACTS						
Pollutant	Averaging Time	Major Sources Impact (μg/m^3)	Background Concentration (μg/m^3)	Total Impact (μg/m^3)	Total Impact Greater than AAQS	Florida AAQS (μg/m^3)
PM_{10}	Annual	1.3	28	29	No	50
	24-hr	11	73	84	No	150

7.2.6 PSD Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration which was established in 1977 (the baseline year was 1975 for existing major sources of SO_2) for SO_2 and 1988 for NO_2. As shown in this table, emissions from the proposed facility are not expected to cause or significantly contribute to a violation of any Class II PSD increment.

PSD CLASS II INCREMENT ANALYSIS				
Pollutant	**Averaging Time**	**Maximum Predicted Impact ($\mu g/m^3$)**	**Impact Greater than Allowable Increment? (Yes/No)**	**Allowable Increment ($\mu g/m^3$)**
PM_{10}	Annual	1	No	17
	24-hr	11	No	30

7.2.7 Impact Analysis Impacts On Soils, Vegetation, And Wildlife

The maximum ground-level concentrations predicted to occur for PM_{10}, CO and SO_2 as a result of the proposed project, including background concentrations and all other nearby sources, will be below the associated AAQS. The AAQS are designed to protect both the public health and welfare. As such, this project is not expected to have a harmful impact on soils, vegetation and wildlife in the vicinity of the project.

7.3.8 Impact On Visibility

Natural gas is a clean fuel and produces little ash. This will minimize smoke formation. The low NO_X and SO_2 emissions will also minimize plume opacity. Because no add-on control equipment and no reagents are required, there will be no steam plume or tendency to form ammoniated particulate species. Due to the distance of the source from the BBNWA, plus the type and amount of emissions from the source, the NPS believes that there is a low potential for visibility impacts. Therefore, no regional haze analysis was required for this project.

7.3.9 Growth-Related Air Quality Impacts

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

8. CONCLUSION

Based on the foregoing technical evaluation of the application and other available information, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations.

M.P. Halpin, P.E. Review Engineer
Cleve Holladay, Meteorologist

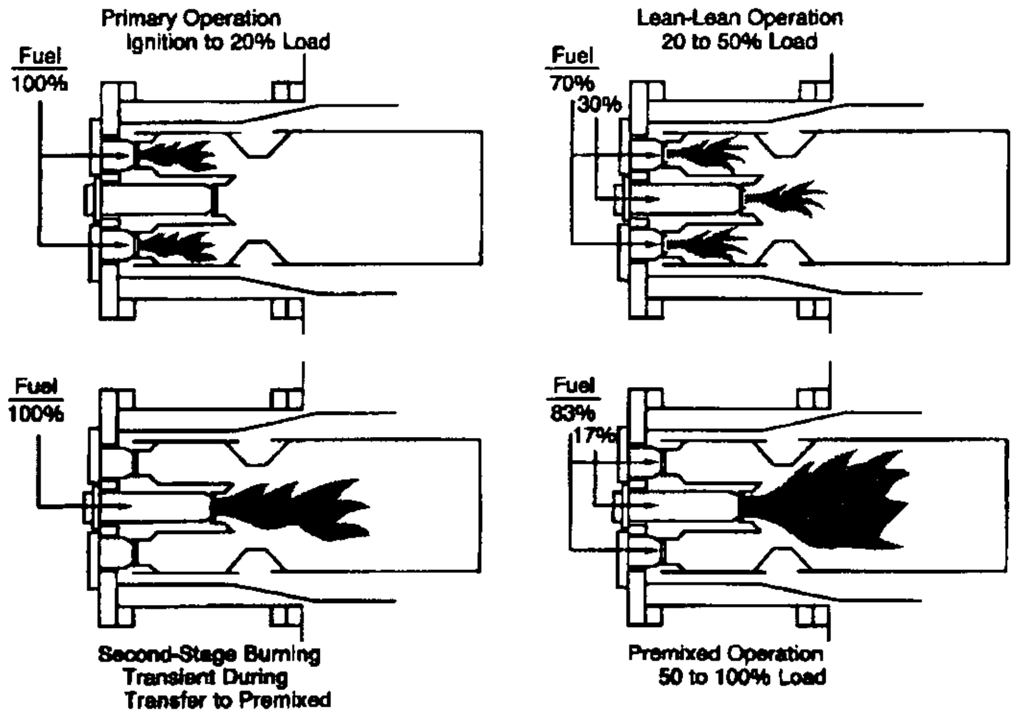
REFERENCES

[1] EPA. "Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines." 1993.

[2] News Release. Goaline Environmental. Genetics Institute Buys SCONOx Clean Air System. August 20, 1999.

[3] News Article. "Control Maker Strives to Sway Utility Skeptics." Air Daily. Volume 5, No. 199. October 14, 1998.

[4] Telecom. Linero, A.A., FDEP, and Beckham, D., U.S. Generating. Circa November 1998.



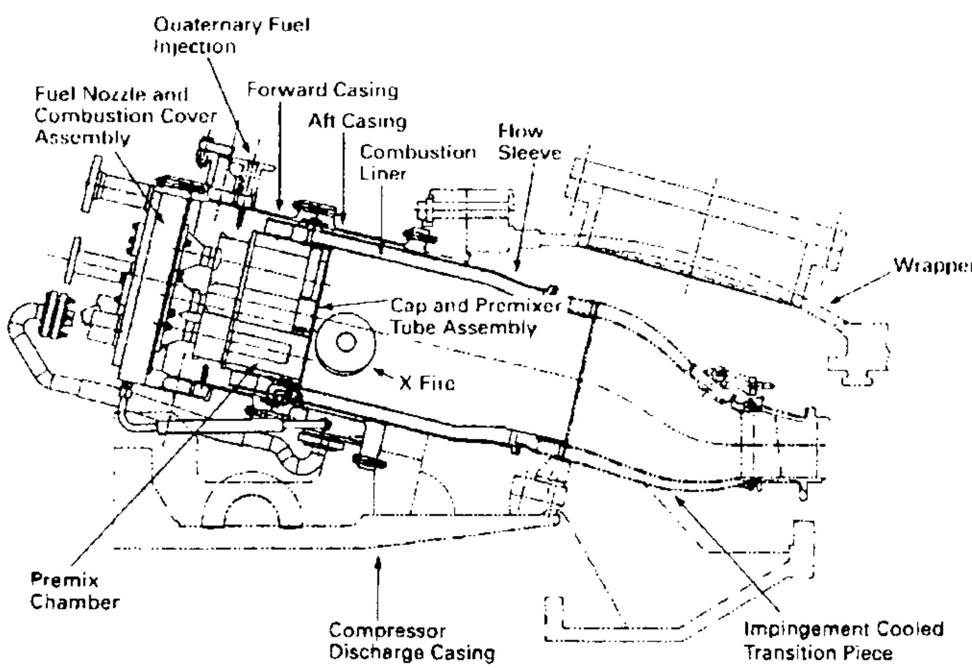


Figure 1 – Dry Low NO_X Operating Modes – DLN-1
Cross Section of GE DLN-2

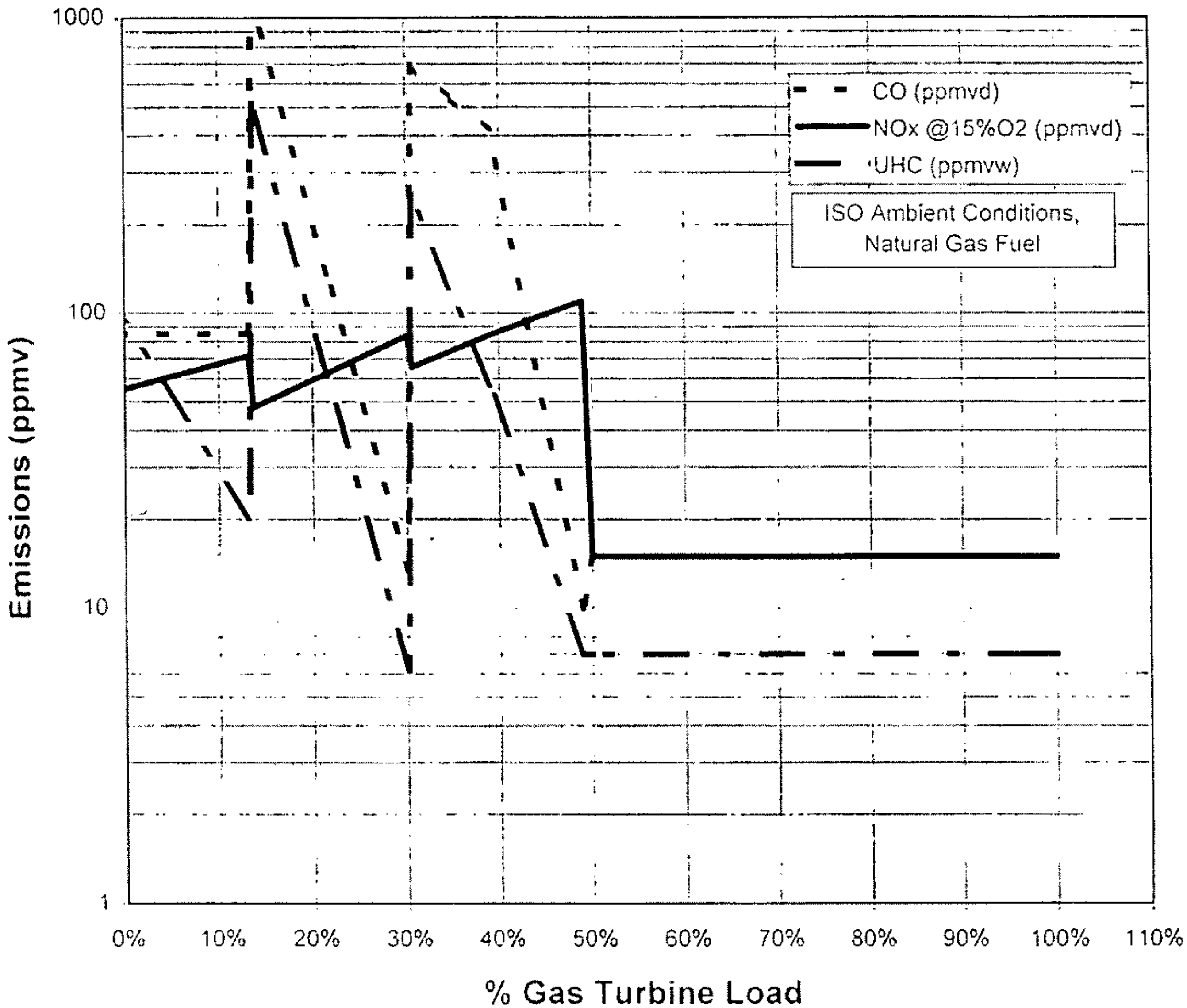


Figure 2 – Emissions Performance Curves for GE DLN-2.6 Combustor Firing Natural Gas in a Dual Fuel GE 7FA Combustion Turbine

(Simple Cycle Intermittent Duty – If Tuned to 15 ppmvd NO_X)

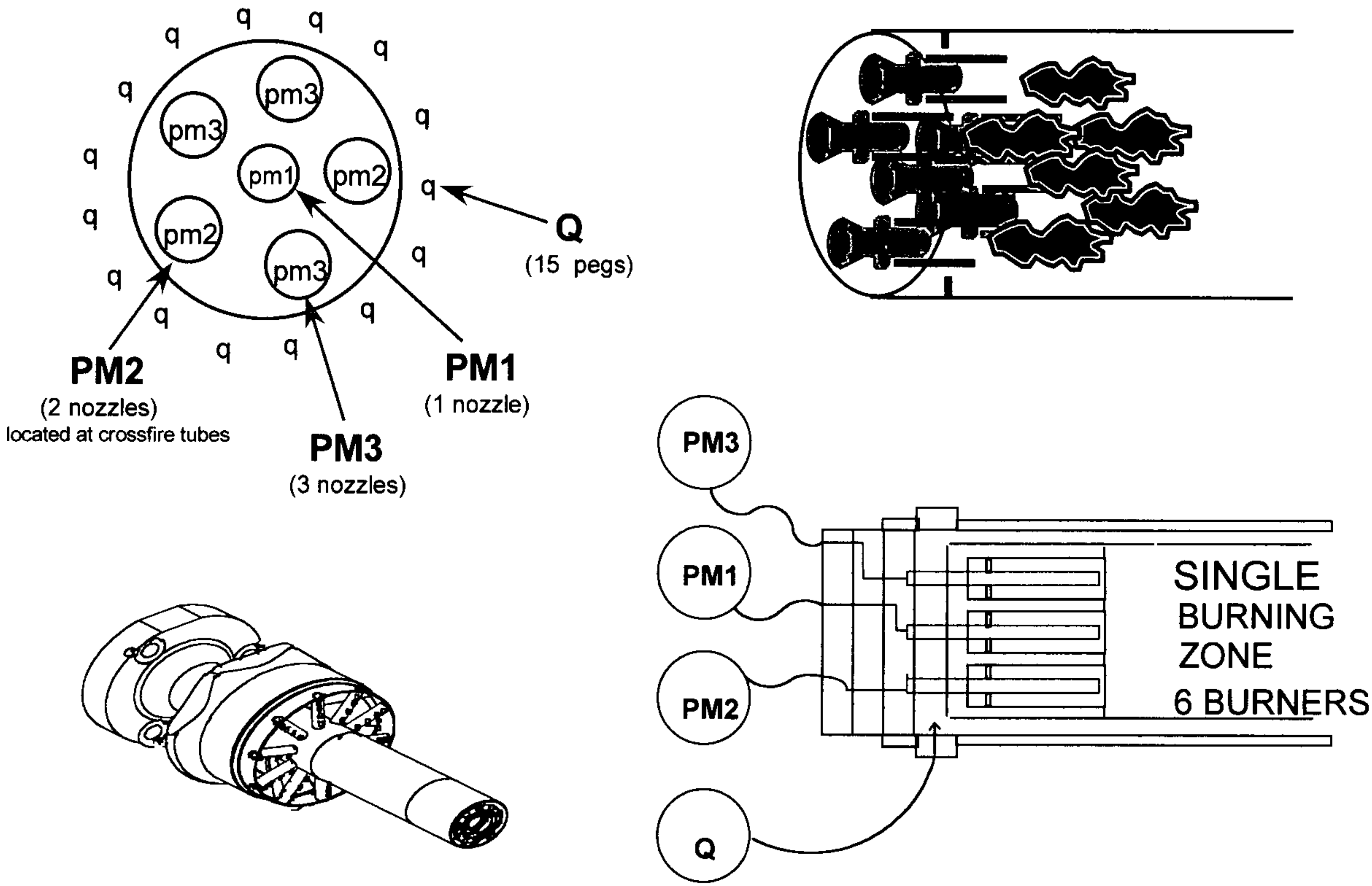


Figure 3 - DLN2.6 Fuel Nozzle Arrangement

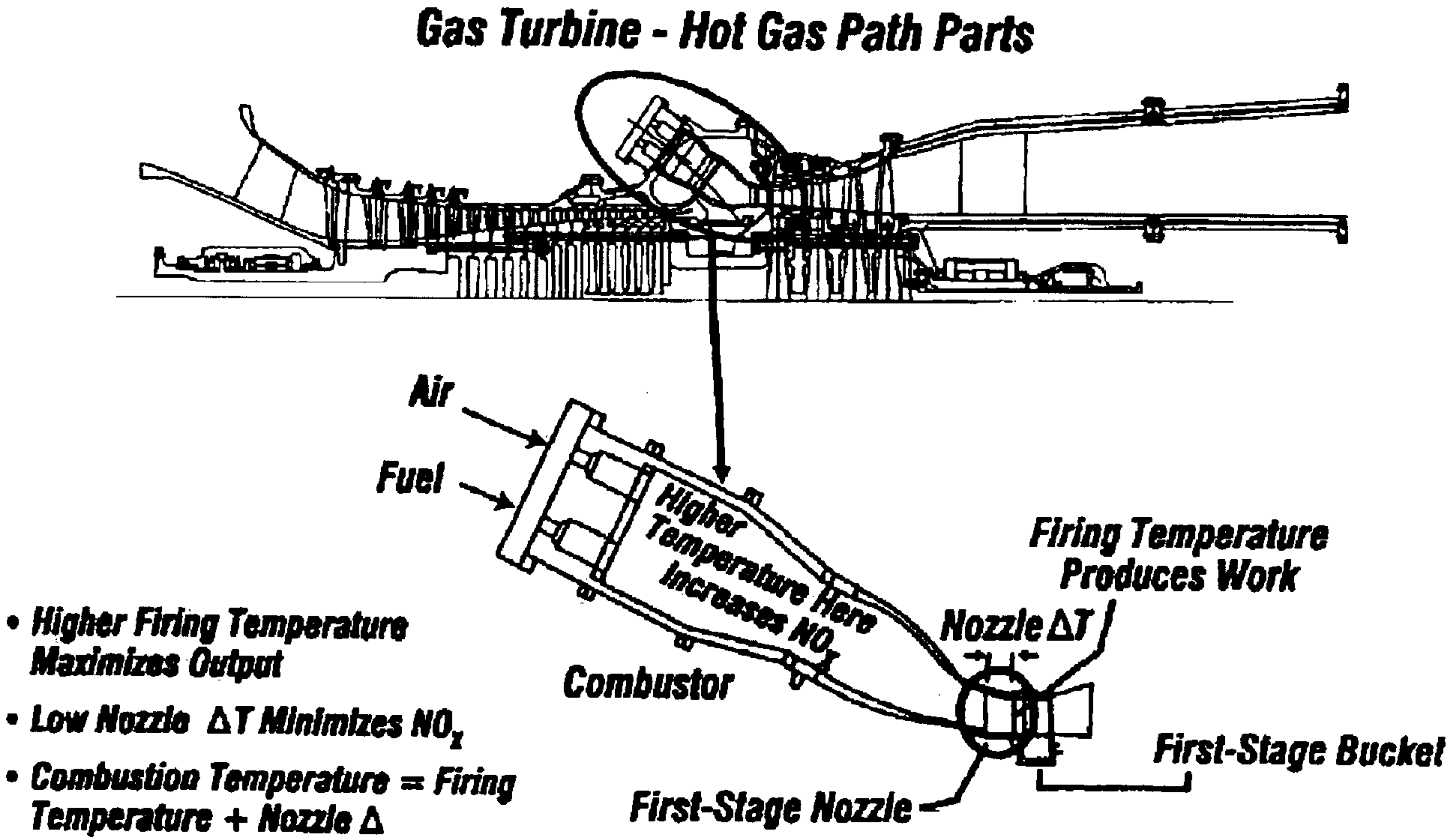


Figure 4 – Relation Between Flame Temperature and Firing Temperature

PERMITTEE:

Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

File No.	PSD-FL-269 (PA99-40)
FID No.	0050014
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative:

Robert G. Moore, V.P. Power Generation/Transmission

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: two nominal 170 megawatt (MW), gas-fired, stationary combustion turbine-electrical generators; two supplementally-fired (275 MMBtu/hr) heat recovery steam generators (HRSGs); a nominal 200 MW steam electrical generator; two 121 foot stacks; and a 10-cell, mechanical draft salt water cooling tower. The unit will achieve approximately 566 megawatt in combined cycle operation at referenced conditions. The unit is designated as Unit 3 and will be located at the Lansing Smith Electric Generating Plant, 4300 Highway 2300, Southport, Bay County. UTM coordinates are: Zone 16; 625.03 km E; 3349.08 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The existing Lansing Smith Electric Generating Plant consists of two oil or coal-fired steam units and one oil-fired combustion (peaking) turbine with a combined summer net generating capacity of approximately 386 megawatts (MW).

The proposed Gulf Smith Unit 3 is a nominal 566 MW combined cycle plant. It will include two nominal 170 MW stationary gas combustion turbines burning natural gas; two supplementally gas-fired heat recovery steam generators; a nominal 200 MW steam electric generator, two 121 foot stacks; and a 10-cell mechanical draft salt water cooling tower. Simple cycle operation is not included within this permitting action. New major support facilities for Unit 3 include water treatment and storage facilities.

Emissions from Gulf Smith Unit 3 will be controlled by Dry Low NO_X (DLN) combustors firing exclusively pipeline quality natural gas. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
004	Power Generation	One nominal 170 MW Gas Combustion Turbine complete with HRSG and Duct Burner
005	Power Generation	One nominal 170 MW Gas Combustion Turbine complete with HRSG and Duct Burner
006	Water Cooling	Cooling Tower

REGULATORY CLASSIFICATION

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X , 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOCs. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-269

SECTION I - FACILITY INFORMATION

This Project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [F.S Chapter 403.503 (12) Definitions]

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

PERMIT SCHEDULE

- xx/xx/99 Notice of Intent published in The
- 11/01/99 Distributed Intent to Issue Permit
- 10/06/99 Application deemed complete and sufficient for PSD review.
- 06/07/99 Received PSD Application

RELEVANT DOCUMENTS:

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

- Application received on June 7, 1999
- Department/BAR letters to Gulf dated June 28, and September 23, 1999
- Comments from the Fish and Wildlife Service dated
- Gulf (through ECT) letters dated September 7 and October 6, 1999
- Department's Intent to Issue and Public Notice Package dated November 1, 1999.
- Letters from EPA Region IV dated
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Northwest District Office, 160 Governmental Center, Pensacola, Florida 32501-5794 and phone number 850/595-8300.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [62-4.070(4), 62-4.210(2)&(3), 62-210.300(1)(a)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 51.166(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a plant conversion. This paragraph states: "For phased construction projects, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source." This reassessment will also be conducted for this project if there are any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission

limits, annual fuel heat input limits or similar changes. [40 CFR 51.166, Rule 62-4.070 F.A.C.]

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

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

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

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

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

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Northwest District Office.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emissions Units 004 and 005. Power Generation, each consisting of a nominal 170 megawatt combustion turbine-electrical generator and a supplementally fired (275 MMBtu/hr) heat recovery steam generator equipped with a natural gas fired duct burner. The CT's will include provisions for the optional use of evaporative coolers and steam power augmentation. The emissions units shall comply with all applicable provisions of 40CFR60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978, adopted by reference in Rule 62-204.800(7), F.A.C.; and 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
5. ARMS Emission Unit 006. Cooling Tower is a regulated emission unit. The Cooling Tower is not subject to a NESHAP because Chromium-based chemical treatment is not used.
6. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Northwest District Office.

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas shall be fired in the unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

8. Combustion Turbine Capacity: The maximum heat input rate, based on the lower heating value (LHV) of the fuel to this Unit at ambient conditions of 65°F temperature, 100% load, and 14.7 psi pressure shall not exceed 1,751 million Btu per hour (mmBtu/hr) when firing natural gas. The maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of each natural gas fired duct burner shall not exceed 275 MMBtu/hour (LHV). [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. 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.

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

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

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

14. Maximum allowable hours of operation for the 566 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

15. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine and Low NO_X burners shall be installed in the duct burner arrangement to comply with the NO_X

emissions limits listed in Specific Conditions 19 and 20 [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

16. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 19 through 24. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

17. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

18. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

19. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15 % O_2 on a dry basis. These limits or their equivalent in terms of lb/hr or NSPS units, as well as the applicable averaging times, are followed by the applicable specific conditions. Each Unit shall be tested to comply with the applicable NSPS and with the BACT limits as indicated below: [Rules 62-212.400, 62-204.800(7)(b) (Subpart GG and Da), 62-210.200 (Definitions-Potential Emissions) F.A.C.]

Emission Unit	NO_X	CO BACT	SO_2/SAM BACT	VOC BACT	PM/Visibility (% Opacity)	Technology and Comments
C.T.'s : Standard Duct Burners	9 ppm 10.6 ppm	13 ppm 16 ppm	2 gr/100 scf natural gas	3 ppm 4 ppm	10 - gas 10 - gas	Dry Low NO_x Combustors Natural Gas, Good Combustion
Steam power Augmentation	13.6 ppm	23 ppm	2 gr/100 scf natural gas	6 ppm	10 - gas	Unit limited to 1000 hours per year of operation
Cooling Tower					18.2 lb/hr	Drift Eliminators

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

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating and the duct burner on shall not exceed 10.6 ppmvd at 15% O_2 (24-hr block average). The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating with steam augmentation and the duct burner on shall not exceed 13.6 ppmvd at 15% O_2 (24-hour block average). Compliance will be determined by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating with the duct burner on shall not exceed 82.9 pounds per hour (lb/hr) and 113.3 lb/hr with steam augmentation to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]

- Emissions of NO_X from the duct burner shall not exceed 0.1 lb/MMBtu, which is more stringent than the NSPS. [BACT, Rule 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limits noted above, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower with duct burners off. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- **Facility-wide NO_X emissions cap**: In addition to individual (point source) emission limits and NO_X averaging plan requirements, the Lansing Smith facility shall be required to comply with a facility-wide NO_X emissions cap of 6666 TPY. CEMS shall be the method of compliance. See specific condition 43 for reporting and record-keeping requirements.
- The installation of low NO_X burners and a new burner management system are authorized for existing Smith Unit 1 (EU-001) as a means of complying with the facility-wide cap. Upon installation and commissioning of these burners, an engineering report shall be submitted to the Department summarizing the observed changes (before versus after) in NO_X, CO and PM_{10}.

21. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating and duct burner on shall exceed neither 16 ppm nor 78.7 lb/hr and with steam augmentation neither 23 ppm nor 116.6 lb/hr to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]
    - Notwithstanding the applicable CO limits noted above, reasonable measures shall be implemented to maintain the concentration of CO in the exhaust gas at 13 ppmvd at 15% O_2 or lower with duct burners off. [Rules 62-212.400 and 62-4.070, F.A.C.]
22. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating and duct burner on shall exceed neither 4 ppm nor 10.2 lb/hr with steam augmentation neither 6 ppm nor 16.8 lb/hr to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]
    - Notwithstanding the applicable VOC limits noted above, reasonable measures shall be implemented to maintain the concentration of VOC in the exhaust gas at 3 ppmvd at 15% O_2 or lower with duct burners off. [Rules 62-212.400 and 62-4.070, F.A.C.]
23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot). Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Condition 44 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed

52.3 tons per year. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review]

24. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without steam augmentation and/or the duct burner and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

25. 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. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during a "warm start-up" or "cold start-up" to combined cycle plant operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. Cold start-up is defined as a startup following a steam turbine shutdown lasting at least 48 hours. During warm start-up, up to three hours of excess emissions are allowed. Warm start-up is defined as a startup following a steam turbine shutdown lasting over 8 hours. [BACT, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

26. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

27. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Northwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 19 through 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

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

29. Initial (I) performance tests shall be performed by the deadlines in Specific Condition 28. Initial tests shall also be conducted after any substantial modifications (and shake down period

not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of SCR or change of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG, Da. Initial (only) NO_X compliance test for the duct burners (Specific Condition 20) shall be accomplished via testing with duct burners "on" as compared to "off" and computing the difference.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

30. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. These excess emissions periods shall be reported as required in Condition 41. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

31. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version). Compliance with the cooling

tower PM limit shall be accomplished via an annual inspection of each of the ten cells and completing all identified maintenance and operation requirements. [BACT]

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

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

34. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

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

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

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

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

MONITORING REQUIREMENTS

40. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the standards, listed in Specific Condition No 19 and 20, shall be reported to the DEP Northwest District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

41. CEMS for reporting excess emissions: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

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

43. CEMS for reporting facility-wide NO_X emissions: The NO_X CEMS shall be used for ensuring compliance with the facility-wide cap. For the oil-fired peaking turbine (Emissions Unit EU-003) emissions may be calculated by using a DEP approved method. Monthly records shall be maintained of the facility-wide NO_X emissions and the owner/operator shall calculate the facility-wide cap on a monthly basis for each prior consecutive 12-month period. These records shall be made available to inspectors as necessary. Additionally, a summary shall be filed with each Annual Operating Report as a means of demonstrating compliance with the facility-wide cap for each consecutive 12-month period. [BACT Determination]

44. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).
- Gulf shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.

45. Determination of Process Variables:

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

46. Subpart Da Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Da].

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Gulf Power Company Lansing Smith Plant
Permit No. PSD-FL-269 and PA 99-40
Southport, Bay County, Florida

BACKGROUND

The applicant, Gulf Power Company (Gulf), proposes to install a combined-cycle power plant at its Lansing Smith Plant located at 4300 Highway 2300, Southport, Bay County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC) sulfur dioxide (SO_2) and sulfuric acid mist (SAM), as well as nitrogen oxides (NO_X). However, the applicant is proposing concurrent installation of low NO_X burners on existing Smith Unit 1, as well as a facility-wide NO_X cap, thereby ensuring no net increase in NO_X emissions. The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary units to be installed are two nominal 170 MW, General Electric 7FA combustion turbine-electrical generators, fired exclusively with pipeline natural gas. The project includes two supplementary-fired heat recovery steam generators (HRSGs) and a steam turbine-electrical generator to produce an additional 200 MW of electrical power. The units will exhaust through individual 121 foot stacks. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated November 2, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on June 7, 1999 and included a proposed BACT proposal. Additional information concerning the application was submitted on September 7 and October 6.

REVIEW GROUP MEMBERS:

Michael P. Halpin, P.E., Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED LIMIT
Particulate Matter	Pipeline Nat. Gas /Comb. Controls	10% Opacity
Volatile Organic Compounds	As Above	3 ppmvd (CTs) - gas 4 ppmvd (w/duct burners) - gas 6 ppmvd (w/DB & stm. aug.) - gas
Carbon Monoxide	As Above	13 ppmvd (CTs) - gas 16 ppmvd (w/duct burners) - gas 23 ppmvd (w/DB & stm. aug.) - gas
Sulfur Dioxide /SAM	As Above	2 gr/100 scf - gas
Nitrogen Oxides	Dry Low NO_X Combustors (CTs) Dry Low NO_X Burners (Unit 1 Boiler)	9 ppmvd (CTs) @ 15% O_2 gas ** 10.6 ppmvd (w/DB) @ 15% O_2 ** 13.6 ppmvd (w/DB & stm. aug.) **

** NOTE: The proposed NO_X emission rates listed are for informational purposes only.

According to the application, the unit will emit approximately 757 tons per year (TPY) of NO_X, 701 TPY of CO, 93 TPY of VOC, 105 TPY of SO_2, 12 TPY of SAM and 253 TPY of PM/PM_{10}.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

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

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

Since this project is not subject to PSD or BACT for NO_X, a related technology review will not be covered herein. This is discussed in detail within the Technical Evaluation and Preliminary Determination, including the details of a federally enforceable facility-wide cap.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppm NO_X @15% O_2. (assuming 25 percent efficiency) and 150 ppm SO_2 @15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by Gulf complies with Subpart GG NSPS which allows NO_X emissions of approximately 110 ppm for the high efficiency unit to be purchased.

The 275 MMBtu duct burners required for supplementary gas-firing of the HRSGs are subject to 40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. The BACT proposed by Gulf is nearly half of the key historically applicable NSPS requirement of 0.20 pounds of NO_X per million Btu heat <u>input</u> (lb. NO_X/MMBtu). It is well below the revised Subpart Da <u>output</u>-based limit of

1.6 lb. NO_X/MW-hr promulgated on September 3, 1998. No National Emission Standards for Hazardous Air Pollutants exist for stationary gas turbines or gas-fired duct burners.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on recent limitations set by EPA and the States for comparable stationary gas turbine.

Project Location	Power Output and Duty	CO - ppm (or lb./MMBtu)	VOC - ppm (or lb./MMBtu)	PM - lb./MMBtu (or gr./dscf or lb./hr)	Technology and Comments
Lakeland, FL	350 MW CC	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen,	308 MW CC	10 - NG 30 - FO	6 - NG 30 - FO	18 lb./hr - NG 55 lb./hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	1500 MW CC	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Tiger Bay, FL	270 MW CC	0.045 lb./MMBtu-NG 0.053 lb./MMBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	485 MW CC	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	260 MW CC	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	461 MW CC	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	1012 MW CC	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	474 MW CC	15 - NG			Clean Fuels Good Combustion
Duke, FL	500 MW CC	12 - NG	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Barry, AL	800 MW CC	0.034 lb./MMBtu - NG/CT 0.057 lb./MMBtu - CT/DB	0.015 lb./MMBtu After CT / DB	0.011 lb./MMBtu CT/DB- 10% Op.	Gas Only Good Combustion

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
CON = Continuous
HSCR = Hot SCR
FO = Fuel Oil
ISO = 59°F
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
LPG = Liquefied Propane Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari
ppm = parts per million

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the information submitted by the applicant and that mentioned above, other information available to the Department consists of:

- Letter from EPA Region IV dated August 11, 1998
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves

COMBUSTION TURBINE AND DUCT BURNER CONTROL TECHNOLOGIES:

The applicant presented an analyses of the different available control technologies for all of the pollutants subject to PSD review and a BACT determination. Technologies for control of pollutants other than NO_X are discussed herein.

Carbon Monoxide (CO) Control

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

Most installations using catalytic oxidation are located in the Northeast. Among them are the 272 Berkshire, Massachusetts facility, 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. However, catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Additionally, Seminole Electric recently proposed catalytic oxidation in order to meet the permitted limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppm at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the CT value of 13 ppm baseload proposed by Gulf appears relatively low, but consistent with the capabilities of DLN-2.6 technology as discussed above. This proposed limits are achievable through good combustion practice. When simultaneously operating the combustion turbine and the duct burner, CO concentrations will be less than 16 ppm and with steam augmentation up to 23 ppm. This is within the range of limits set for combustion turbines operating alone. Annual emissions of CO are expected to be at a maximum of 701 tons per year for all operating modes combined.

Volatile Organic Compound (VOC) Control

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC for both the turbine and the duct burner. The CT proposed limit is 3 ppm. According to GE, even lower VOC emissions were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[1] VOC concentrations will be less than 6 ppm for simultaneous operation of the combustion turbines, duct burners firing and steam augmentation.

Particulate Matter (PM/PM_{10}) Control

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

Natural gas will be the only fuel fired and is efficiently combusted in gas turbines. Clean fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. This has been chosen as BACT by the applicant, the Department concurs. Annual emissions of PM/PM_{10} are expected to be a maximum of 253 tons per year for simultaneous operation of the combustion turbines, duct burners firing and steam augmentation.

Drift eliminators shall be installed on the salt-water cooling tower to reduce PM/PM_{10}. The drift eliminators shall be designed and maintained to reduce drift to 0.001 percent of the circulating water flow rate. No PM testing is required because the Department's Emission Monitoring Section has determined that there is no appropriate PM test method for this type of cooling tower.

BACKGROUND ON SELECTED GAS TURBINE AND DUCT BURNER

Gulf Power has purchased two 170 MW General Electric MS7241FA gas turbines and two HRSGs with duct burners to drive a steam turbine-electrical generator.

The first commercial GE 7F Class unit was installed at the Virginia Power Chesterfield Station in 1990.[2] The initial units had a firing temperature of 2300°F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400°F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine. The line was redesignated as the 7FA Class.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[3] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppm of CO, and 0-0.17 ppm of VOC.[4] The City of Tallahassee recently received approval to install a GE 7FA Class unit at its Purdom Plant.[5] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[6] FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for six GE 7241FA turbines to be installed at the Fort Myers Repowering project.[7] The Santa Rosa Energy Center in Pace, Florida also received a permit with a 9 ppmvd NO_X limit for a GE 7241 turbine with DLN-2.6 burners.[8]

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

GE's approach of progressively refining such technology is a proven one for the large frame units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[9] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[10] Unit 2 is equipped with DLN-2 combustors. According to GE, similar performance is expected soon on the 7FA line such as the ones that will be installed for the Gulf Power Lansing Smith Project. Performance guarantees less than 9 ppmvd can be expected using the DLN-2.6 combustors for units delivered in a couple of years.[11]

General Electric, other manufacturers, and their customers are relying on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combined cycle turbines in Florida. Caution is still advised, however, based on some unexpected setbacks in GE's line of smaller aero-derivative units. Where required by BACT determinations of certain states, General Electric incorporates SCR in combined cycle projects.[12]

The 9 ppm NO_x limit on natural gas (10.6 ppm while firing duct burners) requested by Gulf is comparable with recent BACT determinations for F Class combined cycle units, such as those previously listed.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Gulf project assuming full load. The emission limits or their equivalents in terms of NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 19 through 24.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 0.1 lb/MMBtu for Duct Burner
VOC	As Above	3 ppm (CT on, DB off) 4 ppm (CT and DB on) 6 ppm (DB and Stm. Aug.)
CO	As Above	13 ppm (CT on, DB off) 16 ppm (CT and DB on) 23 ppm (DB and Stm. Aug.)
SO_2 /SAM	As Above	2 gr/100 scf - gas
Cooling Tower PM	Annual Inspection / O&M Plan	18.2 lb/hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- Gulf can obtain a guarantee from GE for DLN-2.6 combustors which have been demonstrated to meet all of the above limits on a 7FA Class gas turbine.
- The turbine emission limits with the duct burners on or off comply with the NSPS and are less than or equal to recent Department BACT determinations applicable to new units at start-up.
- Although the project will "net out" of PSD review for NO_X, these limits will be incorporated into the permit.
- PM_{10} emissions will be very low and difficult to measure. The Department will set a visible emission standard of 10 percent opacity.
- CO emissions from Gulf's project are typical (approximately 11 ppm). The Department will set CO limits achievable by good combustion equal to 13 ppm. Although this unit will fire no oil, short-term emission limits of up to 23 ppm are considered reasonable. The Department will require annual testing for the baseload emission limit.
- VOC emissions of 3 ppm proposed by Gulf are typical values of prior determinations of BACT. Good Combustion is sufficient to achieve these low levels with the DLN-2.6 combustors while firing natural gas. A maximum VOC emission limit of 6 ppm while firing

duct burners and utilizing steam augmentation for up to 1000 hours per year is determined to be BACT.

- Gulf evaluated the use of an oxidation catalyst designed for 80 percent reduction and having a three-year catalyst life. The oxidation catalyst control system was estimated by Gulf to increase the total capital cost of the project by $2,605,195. Gulf estimated levelized costs for CO catalyst control at about $1,600 per ton to control CO emissions to 140 TPY (from 701 TPY).
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Therefore, the Department will set a Visible Emission standard of 10 percent opacity consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Lakeland, the City of Tallahassee, and the FPL Fort Myers projects in Florida as well as the Barry, Alabama project.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (24-hr average)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 29 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: For 1 hour following a steam turbine shutdown less than or equal to 8 hours.
Warm Start: For 2 hours following a steam turbine shutdown between 8 and 48 hours.
Cold Start: For 4 hours following a steam turbine shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the steam turbine unit has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[13]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

Michael P. Halpin, P.E., Review Engineer
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

References

[1] Telecon. Vandervort, C., GE, and Linero, A. A., DEP. "VOC Emissions from FA Gas Turbines with DLN-2.6 Combustors."
[2] Brochure. General Electric. "GE Gas Turbines - MS7001FA." Circa 1993.
[3] Davis, L.B., GE. "Dry Low NO_X Combustion Systems for GE Heavy Duty Gas Turbines." 1994.
[4] Report. Florida Power & Light. "Final Dry Low NO_X Verification Testing at Martin Combine Cycle Plant." August 7, 1995.
[5] Florida DEP. PSD Permit, City of Tallahassee Purdom Unit 8. May, 1998.
[6] City of Tallahassee. PSD/Site Certification Application. April, 1997.
[7] Florida DEP. Intent to Issue Permit. FPL Fort Myers Repowering Project. September, 1998.
[8] Florida DEP. Final Permit. Santa Rosa Energy Center. December, 1998.
[9] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN-2.6 Program
[10] Florida DEP. Bureau of Air Regulation Monthly Report. June, 1998.
[11] Telecon. Schorr, M., GE, and Linero, A.A., Florida DEP. August, 1998. Cost effectiveness of DLN versus SCR.
[12] State of Alabama. PSD Permit, Alabama Power/Barry Sithe/IPP (GE 7FA).
[13] General Electric. Combined Cycle Startup Curves. June 19, 1998.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

Memorandum

Florida Department of
Environmental Protection

TO: Clair Fancy

THRU: Al Linero *aaf 10/31*

FROM: Michael P. Halpin *MH*

DATE: November 1, 1999

SUBJECT: Gulf Power Lansing Smith Unit 3
A 566 MW Combined Cycle Unit
DEP File No. PP 99-40 (PSD-FL-269)

Attached is the public notice package for construction of a natural gas-fired combined cycle, 566 MW generating unit planned for the Gulf Power Lansing Smith Facility. This unit consists of two GE 7FA combustion turbines, each with a supplementally fired HRSG for use with a 200 MW steam turbine.

The applicant will accept a facility-wide Nitrogen Oxides (NO_X) emissions cap of 6666 TPY, which is representative of past operation of the existing units and consistent with prior Determinations (such as FPL's Orimulsion project). Through this permitting action, Gulf will be concurrently authorized to install low NO_X burners on Smith Unit No. 1 as a means of achieving the cap. Hence, the proposed NO_X emissions (of the new unit 3) were not established by BACT. However, Gulf's proposal for Nitrogen Oxides (NO_X) emissions from the gas turbines is reasonably consistent with similar facilities and will be controlled by Dry Low NO_X (DLN-2.6). We propose to require that the unit meet the manufacturer's guarantee of 10.6 ppm on a continuous (24-hour average) basis. This emission rate incorporates the use of duct burners, which Gulf will be authorized to use continuously. Additionally, steam augmentation will be authorized for up to 1000 hours per year during which time NO_X emissions up to 13.6 ppm are authorized.

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, especially, the design of the GE unit.

For reference, the BACT for Santa Rosa provides for a limit (with duct burners firing) of 9.8 ppm NO_X, 24 ppm CO and 8 ppm VOC. This compares to the Gulf unit's proposed limits (also with duct burners firing) of 10.6 ppm NO_X, 23 ppm CO and 4 ppm VOC.

The facility-wide cap referenced in the Draft permit within Specific Condition 20 will use CEMS as the compliance tool and require annual reporting (see Condition 43). It is noteworthy that the operation of the existing units 1 and 2 will be limited as a result of a plant-wide NO_X emissions cap requested by Gulf. The existing units are currently included within a company-wide NO_X averaging plan, which allows for unit 1 to operate at a NO_X emission rate higher than the promulgated Phase II limit. Without the emission cap, but incorporating Phase II NO_X emission limits of 0.40 lb./MMBtu on each existing emission unit (001 and 002), emissions could be as high as 3407 TPY (Unit 1) and 3935 (Unit 2) for a total of 7342 TPY. Additionally, there are uncontrolled emissions from the small diesel-fired peaking unit EU-003 (reported at 94 tons in 1998). Therefore, the proposed facility-wide cap is more stringent than the Phase II limits (which are more stringent than the averaging plan) even prior to including the new combined cycle unit within the cap.

Accordingly, I recommend your approval of the attached Intent to Issue.

AAL/mph

Attachments

P.E. Certification Statement

Gulf Power Company
Lansing Smith Unit 3
Bay County

DEP File No.: PA 99-40 (PSD-FL-269)
Facility ID No.: 0050014

Project: Air Construction Permit

I HEREBY CERTIFY that the engineering features described in the above referenced application and related additional information submittals, if any, 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).

Cleve Holladay and I conducted this review.

(Seal)

Michael P. Halpin, P.E.
Registration Number: 31970

10/29/99
Date

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

Telephone: 850/488-0114
Fax: 850/922-6979