Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 9, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Brian Chatlosh, Manager
Lake Worth Generation, L.L.C.
245 Winter Street, Suite 300
Waltham, MA 02451

Re: DEP File No. PSD-FL-266
Lake Worth Generation, LLC
260 Megawatt Combined Cycle Combustion Turbine Project

Dear Mr. Chatlosh:

Enclosed is one copy of the Draft PSD Permit, Technical Evaluation and Preliminary Determination, and Draft BACT Determination, for the above referenced project to be located at Worth at 117 College Street in Lake Worth, Florida. 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 Mr. Jeff Koerner, P.E. at 850/414-7268.

Sincerely,

7/9

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

CHF/AAL/jfk

Enclosures

Z 333 618 196

US Postal Service
Receipt for Certified Mail
No Insurance Coverage Provided.
Do not use for International Mail *(See reverse)*

Sent to Brian Chatlosh	
Street & Number Lake Worth	
Post Office, State, & ZIP Code Waltham Ma	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date	7-9-99

PS Form 3800, April 1995

Is your RETURN ADDRESS completed on the reverse side?

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

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Brian Chatlosh, Mgr.
Lake Worth Gen.
245 Winter St., Suite 300
Waltham, MA 02451

4a. Article Number
Z 333 618 196

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

7. Date of Delivery
7/19/99

5. Received By: *(Print Name)*

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

6. Signature: *(Addressee or Agent)*
X R. Serreville

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

Thank you for using Return Receipt Service.

In the Matter of an
Application for Permit by:

Mr. Brian Chatlosh, Manager
Lake Worth Generation, L.L.C.
245 Winter Street, Suite 300
Waltham, MA 02451

Facility I.D. No. 0990568
DRAFT Permit No.: PSD-FL-266
New Combined Cycle Gas Turbine Project
Palm Beach 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, Lake Worth Generating, LLC, applied on March 15, 1999 to the Department for a PSD permit to construct a 260 megawatt combined cycle unit consisting of: a maximum 186 MW combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator (74 MW); an absorption chiller, and two stacks. The new plant will be located at at 117 College Street in Lake Worth, Florida

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 permit under the provisions for the Prevention of Significant Deterioration (PSD) of Air Quality is required for the proposed 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 30 (thirty) 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.

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.

7/9

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this INTENT TO ISSUE PSD PERMIT (including the PUBLIC NOTICE, Technical Evaluation and Preliminary Determination, Draft BACT Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 7-9-99 to the person(s) listed:

Mr. Brian Chatlosh, LWG*
Mr. Gregg Worley, EPA
Mr. John Bunyak, NPS
Mr. Isidore Goldman, DEP-SED
Mr. Jim Stormer, PBCHD
Mr. Ken Kosky, Golder Associates
Mr. Paul Doherty, Thermo ECOtek

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.

Sandra Knight 7-9-99
(Clerk) (Date)

PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. PSD-FL-266

Lake Worth Generating, LLC
260 MW Combustion Turbine
Palm Beach County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Lake Worth Generating, LLC. The draft permit authorizes construction of a 260-megawatt (MW) combustion turbine fired primarily with natural gas and low sulfur distillate oil as a backup fuel. The unit is capable of operating in a simple cycle mode of direct power generation or a combined cycle mode with a heat recovery steam generator (HRSG) and supplemental duct burners. The project includes a 98-foot tall simple cycle bypass stack, a 150-foot tall combined cycle HRSG stack, and an absorption chiller system. The project will be located at 117 College Street in Lake Worth, Palm Beach County, Florida. A Best Available Control Technology (BACT) determination was required for particulate matter (PM/PM_{10}), nitrogen oxides (NOx), carbon monoxide (CO), sulfuric acid mist (SAM), and sulfur dioxide (SO_2)pursuant to Rule 62-212.400, F.A.C. and 40 CFR 52.21. The applicant is Lake Worth Generation, L.L.C., 245 Winter Street, Suite 300, Waltham, MA 02451. The authorized representative is Brian Chatlosh, Manager.

The new unit will be a General Electric PG7241FA combustion turbine-electrical generator capable of producing 186 MW (maximum) in simple cycle mode or 250 MW in combined cycle mode. The unit will operate primarily on natural gas and will be permitted to operate 8760 hours per year of which no more than an equivalent 750 hours will be on distillate oil containing no more than 0.04% sulfur by weight. NOx emissions will be controlled by dry low-NOx (DLN) combustors capable of achieving emissions of less than 9.0 parts per million by volume at 15 percent oxygen. The draft permit authorizes steam injection for power augmentation and HRSG duct firing as alternate modes of operation. Because these modes of operation can substantially increase NOx and CO emissions, the draft permit allows the applicant to install selective catalytic reduction (NOx) and/or an oxidation catalyst (CO) to ensure compliance during these power peaking conditions. More stringent emission standards will apply if the optional control equipment is installed. NOx will be controlled under the minimal back-up fuel oil operation by water injection. SO2 and PM/PM10 will be limited by use of clean fuels. Emissions of VOC will be controlled by good combustion practices.

Based on the original application, the maximum potential emissions in tons per year are summarized in the following table. Final potential emissions were less due to the further restrictions on oil firing.

Pollutants	Maximum Potential Emissions	Major Emissions Threshold	PSD Significant Emission Rate
PM/PM_{10}	43	NA	25/15
SO_2/SAM	70 / 11	NA	40
NOx	438	100	40
VOC	39	NA	40
CO	204	100	100

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 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:

Dept. of Environmental Protection	Dept. Environmental Protection	Palm Beach County Health Dept.
Bureau of Air Regulation	Southeast District Office	Air Pollution Control Section
111 S. Magnolia Drive, Suite 4	400 N. Congress Avenue	901 Evernia Street
Tallahassee, Florida 32301	West Palm Beach, Florida 33401	West Palm Beach, FL 33401
Telephone: 850/488-0114	Telephone: 561/681-6600	Telephone: 561/355-3136
Fax: 850/922-6979	Fax: 561/681-6790	Fax: 561/355-2442

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

DRAFT PERMIT

PERMITTEE

Lake Worth Generation, L.L.C.
245 Winter Street, Suite 300
Waltham, MA 02451

Authorized Representative:
Brian Chatlosh, Manager

ARMS ID No.	099-0568
PSD Permit No.	PSD-FL-266
ARMS Permit No.	099-0568-001-AC
Permit Expires:	(Draft)
SIC No.	4911

PROJECT AND LOCATION

This permit authorizes Lake Worth Generating, L.L.C. to construct a gas-fired combustion turbine with electrical generator and associated equipment in accordance with the application and conditions of this permit. The new electrical generating power plant will be collocated at the existing Tom G. Smith Power Plant owned and operated by the City of Lake Worth at 117 College Street in Lake Worth, Florida 33461. The UTM Coordinates are Zone 17, 592.8 km E, 43.7 km N.

STATEMENT OF BASIS

This construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). The above named permittee is authorized to construct the emissions units 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).

APPENDICES

The attached appendices are a part of this permit:

Appendix A: Terminology
Appendix B: Construction Permit General Conditions
Appendix C: Department's BACT Determination
Appendix D: NSPS General Provisions
Appendix E: NSPS Subpart Db (HRSG Duct Burner)
Appendix F: NSPS Subpart GG (Gas Turbine)
Appendix G: Summary Report - Gaseous Excess Emission & Monitoring System Performance

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources
Management

FACILITY DESCRIPTION

This permit authorizes the installation of a new combustion gas turbine and heat recovery steam generator capable of operating in either simple cycle or combined cycle modes. The permittee will lease property from the City of Lake Worth which also operates the Tom G. Smith Power Plant located on the same site. Employees of the existing power plant will operate and maintain the new combustion gas turbine. Although the combustion turbine may have significant simple cycle operation, it will deliver steam during combined cycle operation when requested by the Tom G. Smith Power Plant. The existing power plant will purchase this steam as a high priority when it is available and when there is a sufficient demand. This new facility consists of the following emissions units.

ARMS ID No.	EMISSIONS UNIT DESCRIPTION
001	The **combustion turbine** is a General Electric Model Frame 7FA primarily fired with natural gas. It has a direct electrical generating capacity of 186 MW in simple cycle mode.
002	The **heat recovery steam generator** (HRSG) converts waste heat from the combustion turbine into steam during the combined cycle mode to produce an additional 74 MW of electricity from existing steam turbines. Supplemental low-NOx duct burners may be fired with natural gas to provide an additional maximum heat input of 175 mmBTU per hour.

REGULATORY CLASSIFICATION

This facility is classified as a "major" or Title V Source of air pollution because emissions of nitrogen oxides (NOx) and carbon monoxide (CO) exceed 100 tons per year.

This facility is not included in the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C. However, nitrogen oxide emissions are greater than 250 tons per year, so the facility is "major" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This facility is not a major source of hazardous air pollutants (HAPs).

This facility is subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

Emissions units included in this project are subject to regulation under the New Source Performance Standards, 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) and Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

Also, emissions units included in this project are subject to regulation under Rule 62-212.400, F.A.C. for a determination of the Best Available Control Technology (BACT).

This project is not subject to Rule 62-17, F.A.C., Power Plant Siting, because steam generated power will be less than 74 MW.

PERMIT SCHEDULE

- 03/15/99 Received PSD permit application.
- 05/24/99 Application deemed complete and sufficient for PSD review.
- 07/09/99 Distributed Intent to Issue Permit.
- (draft) Notice of Intent published in (draft).

RELEVANT DOCUMENTS

The documents listed below are the basis of the permit. They are specifically related to this permitting action. These documents are on file with the Department.

- Permit application and associated correspondence.
- National Park Services' comments dated 04/16/99 and 06/21/99.
- Department's Technical Evaluation and Preliminary Determination dated 07/09/99.
- Department's Intent to Issue and Public Notice Package dated 07/09/99.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit dated (DRAFT)

The following specific conditions apply to all emissions units at this facility addressed by this permit.

ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: 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 at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, phone number 850/488-0114.

2. Compliance Authorities: All documents related to reports, tests, minor modifications and notifications shall be submitted to the Air Pollution Control Section of the Palm Beach County Health Department at P.O. Box 29 (901 Evernia Street), West Palm Beach, Florida 33402-0029, phone number 561/355-3136 and fax number 561/355-2442. Copies of these items shall also be submitted to the Air Program of the Department's Southeast District Office at P.O. Box 15425 (400 North Congress Avenue), West Palm Beach, Florida, 33416-5425, phone number 561/681-6600, and fax number 561/681-6790.

3. 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.]

4. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code. *Appendix A* lists abbreviations and methods for citing regulations used throughout this permit.

5. General Conditions: The owner and operator is subject to, and shall operate under, the attached General Conditions G.1 through G.15 listed in *Appendix B* of this permit. General Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

6. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission units 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, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Title 40, Parts 52, 60, 72, 73, and 75. 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.]

7. Modifications: No emissions unit or facility subject to this permit shall be constructed or modified without obtaining an air construction permit from the Department. Such permit must be obtained prior to the beginning of construction or modification. [Chapters 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

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

9. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department

may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]

10. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]

11. 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.).

12. 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 Department'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]

13. 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 copies to the Compliance Authorities. [Chapter 62-213, F.A.C.]

EMISSION STANDARDS

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

15. General Pollutant Emission Limiting Standards:

    (a) The owner or operator shall periodically inspect valves, piping, fittings, and storage tanks related to the fuel handling systems for leaks and repair. [Rule 62-296.320(1), F.A.C.]

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

OPERATIONAL REQUIREMENTS

16. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by hazard of fire, wind or by other cause, the permittee shall notify the Compliance Authorities within one (1) working day. The notification shall include pertinent information as to the cause of the problem, and what steps are being taken to correct the problem and to prevent its 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 Department rules. [Rule 62-4.130, F.A.C.]

17. Circumvention: No person shall circumvent any air pollution control device or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

COMPLIANCE MONITORING AND TESTING REQUIREMENTS

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

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

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

21. Test Procedures shall meet all applicable requirements of Rule 62-297.310(4), F.A.C.

22. Determination of Process Variables: The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards. Equipment or instruments used to directly, or indirectly, determine process variables 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. Examples of such devices include belt scales, weight hoppers, flow meters, and tank scales. [Rule 62-297.310(5), F.A.C.]

23. Required Stack Sampling Facilities: All emissions units requiring stack testing shall be designed to accommodate testing and sampling facilities. Sampling facilities shall conform to the requirements of Rule 62-297.310(6), F.A.C. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

24. Test Notification: The owner or operator shall notify the Compliance Authorities at least 30 days prior to the scheduled initial NSPS tests and at least 15 days prior to all other scheduled

compliance tests. Notification shall include the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and conducting the test. [Rule 62-297.310(7)(a)9., F.A.C. and 40 CFR 60.8]

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

Reporting and Record Keeping Requirements

26. Records Retention: All measurements, records, and other data required by this permit 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 the Department's representatives upon request. [Rule 62-213.440, F.A.C.]

27. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical, but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. [Rule 62-297.310(8), F.A.C.]

28. Excess Emissions Reporting: If excess emissions occur, the owner or operator shall notify the Compliance Authorities within one (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. Within thirty (30) days following each calendar quarter, the owner or operator shall submit a report summarizing any incident of the excess emissions or stating that no excess emissions occurred during the given calendar quarter. The summary of each incident shall include the amount, the duration, the cause, and the action taken to minimize and correct the excess emissions. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Periods of startup, shutdown, and malfunction shall be monitored, recorded, and reported as excess emissions when monitored emission levels exceed any permitted standards. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)]

29. Annual Operating Report (AOR): The Annual Operating Report for Air Pollutant Emitting Facility shall be completed each year and shall be submitted to the Compliance Authorities by March 1 of the following year. [Rule 62-210.370(3), F.A.C.]

The specific conditions of this section address the following emissions units.

ARMS ID No.	EMISSIONS UNIT DESCRIPTION
001	The **combustion turbine** consists of a Model PG7241(FA) manufactured by General Electric capable of operating alone in simple cycle mode or in combination with Emissions Unit No. 002 (HRSG) in combined cycle mode. When firing natural gas as the primary fuel, the combustion turbine design incorporates dry low-NOx (DLN) combustion technology to reduce thermal NOx formation by premixing fuel and air prior to combustion and staging combustion to decrease the flame temperature. A water injection system will be used to reduce the flame temperature to control NOx emissions when firing low sulfur distillate oil as a backup fuel. The General Electric Speedtronic™ Gas Turbine Control System will monitor and control the gas turbine combustion process and operating parameters, including: fuel distribution, fuel staging, turbine speed, load conditions, combustion temperature, water injection, and fully automated start-up, shutdown, and cool-down. An absorption chilling system will cool the turbine inlet air to a nominal 55°F producing a greater mass flow rate with a corresponding increase in power production. Continuous monitors will record the emissions of nitrogen oxides as well as the ratio of control water-to-fuel ratio during oil firing. In simple cycle operation, the gas turbine directly generates a maximum of 186 MW of electricity. The bypass stack is 22 feet in diameter and 98 feet tall and used for simple cycle operation. When firing natural gas, exhaust gases exit the bypass stack at a temperature of 1110°F with a velocity of 118 feet per second and a volumetric flow rate of 2,681,000 actual cubic feet per minute. When firing low sulfur distillate oil, exhaust gases exit the bypass stack at a temperature of 1080°F with a velocity of 121 feet per second and a volumetric flow rate of 2,763,000 actual cubic feet per minute. The exhaust gas parameters given are the maximum considering base load operation and a minimum, chilled turbine inlet air temperature of approximately 45°F.
002	The **heat recovery steam generator** (HRSG) converts waste heat from the combustion turbine into steam during the combined cycle mode of operation. The steam is sold to the T.G. Smith plant for use in existing steam turbines to generate up to 74 MW of additional electricity. Supplemental low-NOx duct burners may be fired with natural gas to provide an additional maximum heat input of 175 mmBTU per hour. During combined cycle operation, exhaust gases exit a separate stack that is 18 feet in diameter and 150 feet tall. When firing natural gas, exhaust gases leave the HRSG stack at a temperature of 200°F with a velocity of 74 feet per second and a volumetric flow rate of 1,128,500 actual cubic feet per minute. When firing low sulfur distillate oil, exhaust gases leave the HRSG stack at a temperature of 220°F with a velocity of 80 feet per second and a volumetric flow rate of 1,217,000 actual cubic feet per minute. The exhaust gas parameters given are based on a chilled inlet air temperature of approximately 45°F and base load operation.

APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: This project is subject to Best Available Control Technology (BACT) determinations for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), and sulfuric acid mist (SAM) in accordance with Rule 62-212.400, F.A.C.

2. NSPS General Provisions

   (a) **NSPS General Provisions**: The combustion turbine (EU-001) and duct burner (EU-002) shall comply with all applicable requirements of 40 CFR 60, Subpart A, General Provisions including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) **Combustion Turbine (EU-001)**: The combustion turbine-electrical generator shall comply with all applicable provisions of 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. *Appendix F* of this permit summarizes the applicable requirements. The Subpart GG requirement to correct test data to ISO conditions applies, however, such correction is not used for compliance determinations with the BACT standards.

   (c) **HRSG Duct Burner (EU-002)**: The heat recovery steam generator (HRSG) may include duct firing with natural gas. The duct burner shall comply with all applicable provisions of 40 CFR 60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, adopted by reference in Rule 62-204.800(7), F.A.C. *Appendix E* of this permit summarizes the applicable requirements.

PERFORMANCE RESTRICTIONS

3. Permitted Capacities

   (a) **Combustion Turbine**: The combustion turbine may be operated in simple cycle or combined cycle modes. In simple cycle mode, the unit is capable of generating up to a maximum of 176/186 MW of power for gas/oil firing. Based on the higher heating value (HHV) of each fuel, an inlet supply air cooled to 45°F, and a 100% base load, the capacity of this unit shall be defined as the following maximum heat input rates.

      (1) The heat input from firing natural gas shall not exceed 1817 mmBTU per hour.

      (2) The heat input from firing low sulfur distillate oil shall not exceed 1965 mmBTU per hour.

   These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's performance curves, corrected for site conditions or equations for correction to other ambient conditions, shall be provided to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing.

(b) **HRSG Duct Burner**: In combined cycle mode with the heat recovery steam generator (HRSG), an additional 74 MW of steam generated power may be produced. In addition, the HRSG may incorporate supplemental firing with a natural gas-fired duct burner. The maximum heat input rate from firing natural gas in the duct burner shall not exceed 175 mmBTU per hour (HHV). The duct burner shall not be fired when the combustion turbine is firing low sulfur distillate oil as a backup fuel.

As a basis for demonstrating compliance with the permitted maximum capacities, the permittee shall install, operate, calibrate, and maintain fuel metering systems to monitor the flow of natural gas and distillate oil to each emissions unit. At a minimum, compliance shall be demonstrated by keeping the records specified in the Daily Operations Log and the Monthly Operations Summary as required by this permit.

[Application (Design); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

4. Alternate Modes of Operation: This permit authorizes operation of the combustion turbine in either simple or combined cycle modes when firing natural gas as the primary fuel or low sulfur distillate oil as the backup fuel. In addition, this permit authorizes limited operation of the combustion turbine when firing natural gas in the combined cycle mode to inject steam for power augmentation or to fire the supplemental HRSG duct burner or both. The specific conditions of this permit effectively limit these alternate modes of operation to 2000 hours per year. Further, the hourly rates of steam injection (pounds per hour) and HRSG duct firing (mmBTU) shall be limited to the rates at which the unit last demonstrated compliance with the emissions standards during these alternate modes of operation. [Application, Rule 62-4.070(3), F.A.C.]

5. Allowable Fuels: The combustion turbine and HRSG duct burner shall be fired by pipeline natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, the combustion turbine may be fired with No. 2 or superior grade distillate fuel oil containing no more than 0.04% sulfur by weight. Compliance with limits on fuel sulfur content shall be demonstrated by complying with the requirements of the Alternate Monitoring Plan in permit condition #31. [Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

6. Fuel Consumption Limits

(a) **Combustion Turbine**: No more than 10,800,000 gallons of low sulfur distillate oil shall be fired in the combustion turbine in any consecutive 12 month period (based on 750 hours at maximum firing capacity and HHV).

(b) **HRSG Duct Burner**: No more than 341.8 million cubic feet of natural gas shall be fired in the HRSG duct burner in any consecutive 12 month period (based on 2000 hours at maximum firing capacity and HHV).

[Applicant Request, Rule 62-210.200, F.A.C. (Definition - Potential Emissions)]

7. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to minimize emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the combustion turbine and pollution control devices in accordance with the guidelines and procedures established by each equipment manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

8. Hours of Operation: Hours of combustion turbine operation when firing natural gas are not restricted (8760 hours per year). Combustion turbine operation when firing low sulfur distillate oil and HRSG duct firing with natural gas are restricted by the fuel consumption limits of this permit. Steam injection for power augmentation is limited to no more than 2000 hours per consecutive 12 months. [Applicant Request; Rule 62-212.400, F.A.C. (BACT); Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

EMISSIONS CONTROLS

9. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain the General Electric Speedtronic™ Gas Turbine Control System. This system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: fuel distribution and staging, turbine speed, load conditions, combustion temperatures, water injection, and fully automated startup, shutdown, and cool-down. [Applicant Request; Rule 62-4.070(3); Rule 62-212.400, F.A.C. (BACT)]

10. Combustion Controls: The owner and operators shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, NOx, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, dry low-NOx (DLN) combustors, and Speedtronic™ control system shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, these systems shall be maintained and tuned, as necessary, to minimize pollutant emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

11. DLN Combustion Technology: To control NOx emissions when firing natural gas, the permittee shall install, tune, operate and maintain dry low-NOx (DLN) combustors on the combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to installation. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

12. Water Injection: To control NOx emissions when firing low sulfur distillate oil, the permittee shall install, calibrate and operate an automated water injection system. This system shall be maintained and adjusted to provide the minimum NOx emissions possible by water injection. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to installation. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

13. Low-NOx HRSG Duct Burner: To control NOx emissions during duct firing, the permittee shall install, tune, operate and maintain low-NOx burners in the HRSG duct burner arrangement. [Design; Rules 62-4.070 and 62-212.400, F.A.C.]

14. Optional Controls: To ensure compliance with NOx and CO emissions limits during periods of power augmentation and duct firing, the permittee may design the heat recovery steam generator to accommodate the installation of selective catalytic reduction (SCR) and/or oxidation catalyst (OC) technologies, respectively. The SCR and OC systems shall be designed and operated to comply with the more stringent emissions standards specified in this permit. The SCR system shall use aqueous ammonia injection with an ammonia slip of no more than 5 ppm. Ammonia slip shall be periodically. [Rules 62-212.400 and 62-4.070, F.A.C.]

EMISSIONS STANDARDS

15. Emissions Standards Summary: Following are the BACT[a] limits determined by the Department for this project. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are provided in the specific conditions following.

Pollutant	Mode of Operation/Controls[b]	Emission Standard
EU-001/002: Combustion Turbine and HRSG With or Without Duct Firing		
CO	Simple or Combined Cycle / DLN (Gas)	12.0 ppmvd @ 15% O2 43.2 pounds per hour
	Simple or Combined Cycle / Wet Injection (Oil)	20.0 ppmvd @ 15% O2 73.4 pounds per hour
	Combined Cycle / Oxidation Catalyst Option (Gas)	4.7 ppmvd @ 15% O2 16.8 pounds per hour
	Combined Cycle / Oxidation Catalyst Option (Oil)	7.8 ppmvd @ 15% O2 28.6 pounds per hour
NOx	Simple or Combined Cycle / DLN (Gas)	9.0 ppmvd @ 15% O2 66.2 pounds per hour
	Simple or Combined Cycle / Wet Injection (Oil)	42.0 ppmvd @ 15% O2 362.4 pounds per hour
	Combined Cycle / SCR Option (Gas)	3.5 ppmvd @ 15% O2 25.8 pounds per hour
	Combined Cycle / SCR Option (Oil)	16.4 ppmvd @ 15% O2 141.3 pounds per hour
PM/PM_{10}	All Modes / Clean Fuels and Combustion Design	Visible emissions - 10% opacity
SAM/SO_2	All Modes / Natural Gas Specification	1 grain per 100 SCF of gas
	All Modes / Low Sulfur Distillate Oil Specification	0.04% sulfur by weight
VOC	All Modes / Combustion Design (Gas/Oil)	3.5/7.0 ppmvw as methane 7.9/16.5 pounds per hour
EU-002: Duct Burner (Alone)		
NOx[C]	Emissions Only From HRSG Duct Firing	0.08 pounds per mmBTU

a The VOC standard is a synthetic minor limit not a BACT limit.

b DLN means dry low-NOX controls. SCR means selective catalytic reduction with ammonia injection. HRSG means heat recovery steam generator. Limits for combined cycle operation are the same whether or not the duct burner is fired or steam is injected for power augmentation.

c These emissions are included in the above NOx limits.

Note: Unless otherwise specified, the following emission standards apply equally to the combustion turbine operating alone or with an alternate mode of operation (power augmentation, HRSG duct firing, or both).

16. Carbon Monoxide (CO)

(a) **Dry-Low NOx Controls**: During simple or combined cycle operation when firing natural gas in the combustion turbine, CO emissions shall not exceed 43.2 pounds per hour nor 12.0 ppmvd based on a 3-hour test average.

(b) **Water Injection**: During simple or combined cycle operation when firing low sulfur distillate oil in the combustion turbine, CO emissions shall not exceed 73.4 pounds per hour nor 20.0 ppmvd based on a 3-hour test average.

(c) **Optional Oxidation Catalyst (OC)**: During combined cycle operation when firing natural gas in the combustion turbine, CO emissions shall not exceed 16.8 pounds per hour nor 4.7 ppmvd based on a 3-hour test average. During combined cycle operation when firing low sulfur distillate oil in the combustion turbine, CO emissions shall not exceed 28.6 pounds per hour nor 7.8 ppmvd based on a 3-hour test average.

The above emissions limits include any emissions resulting from power augmentation and/or duct firing. The permittee shall demonstrate initial and annual compliance with the CO emissions standards by conducting emissions compliance tests in accordance with EPA Method 10 and the performance testing requirements of this permit.

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

17. Nitrogen Oxides (NOx)

(a) **Dry-Low NOx Controls**: During simple or combined cycle operation when firing natural gas in the combustion turbine, NOx emissions shall not exceed 66.2 pounds per hour nor 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average (24-hour block average for continuous compliance).

(b) **Water Injection**: During simple or combined cycle operation when firing low sulfur distillate oil in the combustion turbine, NOx emissions shall not exceed 362.4 pounds per hour nor 42.0 corrected to 15% oxygen based on a 3-hour test average (3-hour block average for continuous compliance).

(c) **Optional Selective Catalytic Reduction (SCR)**: During combined cycle operation when firing natural gas in the combustion turbine, NOx emissions shall not exceed 25.8 pounds per hour nor 3.5 ppmvd corrected to 15% oxygen based on a 3-hour test average (3-hour block average for continuous compliance). During combined cycle operation when firing low sulfur distillate oil in the combustion turbine, NOx emissions shall not exceed 141.3 pounds per hour nor 16.4 ppmvd corrected to 15% oxygen based on a 3-hour test average (3-hour block average for continuous compliance).

The above emissions limits include any emissions resulting from power augmentation and/or duct firing. NOx emissions are defined as emissions of oxides of nitrogen measured as NO_2. The permittee shall demonstrate initial and annual compliance with the above NOx standards based on the 3-hour test average by conducting emissions compliance tests in accordance with EPA Methods 7E/20 and the performance testing requirements of this permit. The permittee shall demonstrate continuous compliance with the above 3/24-hour block averages by recording the continuous emissions monitoring data required by this permit.

(d) **HRSG Duct Burner Only**: NOx emissions from firing only the HRSG duct burner shall not exceed 0.08 pounds per million BTU of heat input based on a 3-hour test average. The permittee shall demonstrate initial compliance with this NOx standard for purposes of the NSPS requirements by conducting emissions compliance tests in accordance with EPA Methods 7E/20 and the performance testing requirements of this permit. This permit does not require periodic compliance testing.

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

18. Particulate Matter (PM/PM_{10}), Sulfuric Acid Mist (SAM) and Sulfur Dioxides (SO2)

(a) **Fuel Specifications**: Emissions of particulate matter, sulfur dioxide, and sulfuric acid mist shall be limited by the good combustion techniques described in this permit and the use of clean fuels. Fuel for the combustion turbine and the HRSG duct burner shall be limited to pipeline natural gas containing no more than 1 grain of sulfur per 100 standard cubic feet of gas. The combustion turbine may be fired with No. 2 or superior grade distillate oil containing no more than 0.04% sulfur by weight as a backup fuel. Compliance with the fuel specifications shall be demonstrated meeting the requirements of the Alternate Monitoring Plan in specific condition #31 and keeping the records specified in this permit.

(b) **VE Standard**: As a surrogate for PM/PM_{10} emissions, visible emissions from the operation of the combustion turbine shall not exceed 10% opacity, based on a 6-minute average. This includes visible emissions from either the bypass stack (simple cycle mode) or the HRSG stack (combined cycle mode). Initial and annual compliance with the visible emissions standard shall be demonstrated by conducting EPA Method 9 in accordance with the performance testing requirements of this permit.

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

19. Volatile Organic Compounds (VOC): During simple or combined cycle operation when firing natural gas in the combustion turbine, VOC emissions shall not exceed 7.9 pounds per hour nor 3.5 ppmw based on a 3-hour test average. During simple or combined cycle operation when firing low sulfur distillate oil in the combustion turbine, VOC emissions shall not exceed 16.5 pounds per hour nor 7.0 ppmw based on a 3-hour test average. The VOC emissions shall be measured and reported as methane. The emissions limits include any emissions resulting from power augmentation and/or duct firing. Compliance with the VOC standards shall be demonstrated by conducting emissions performance tests in accordance with EPA Methods 18, 25, and/or 25A and the performance testing requirements of this permit. Compliance testing shall be performed for the initial startup and during the fiscal year prior to renewal of the operation permit. Continuous compliance shall be demonstrated by the use of good operating practices and compliance with the CO emissions standards. [Application, Design, Rule 62-4.070(3), F.A.C.]

EXCESS EMISSIONS

20. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations. Excess emissions resulting from the operation of the duct burner shall be prohibited. [Rule 62-210.700, F.A.C.]

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction of the combustion turbine shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall not exceed two hours in any 24-hour period except for the following modes of startup.

(a) **Warm Startup**: During a warm start-up to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine shutdown lasting 8 hours or more, but less than 48 hours.

(b) **Cold Startup**: During a cold startup to combined cycle operation, up to four hours of excess emissions are allowed in a 24-hour period. "Cold startup" is defined as startup to combined cycle operation following a steam turbine shutdown lasting 48 hours or more.

If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authorities within one (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. [Applicant Request, Vendor Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]

COMPLIANCE MONITORING AND RECORD KEEPING REQUIREMENTS

22. Sampling Facilities: The permittee shall design the stacks for the combustion turbine and heat recovery steam generator to accommodate adequate testing and sampling locations for compliance with the applicable emission limits and testing modes. This includes proper sampling ports before and after the duct burner. [Rules 62-4.070 and 62-204.800, F.A.C., and 40 CFR 60.40a(b)]

23. Combustion Turbine Testing Capacity: 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. However, 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. [Rule 62-297.310(2), F.A.C.]

24. Performance Test Methods: Compliance tests shall be performed in accordance with the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

    (a) **EPA Method 7E**, "Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)".

    (b) **EPA Method 9**, "Visual Determination of the Opacity of Emissions from Stationary Sources".

    (c) **EPA Method 10**, "Determination of Carbon Monoxide Emissions from Stationary Sources". All CO tests shall be conducted concurrently with NOx tests.

    (d) **EPA Method 20**, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines."

    (e) **EPA Methods 18, 25 and/or 25A**, "Determination of Volatile Organic Concentrations."

    No other test methods may be used for compliance testing unless prior DEP approval is received in writing from the DEP Emissions Monitoring Section Administrator in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.

25. Initial Tests Required: Initial compliance with the allowable emission standards specified in this permit shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days after initial operation of the emissions units. Initial compliance with the allowable emission limiting standards specified in this permit shall also be determined within 45 days after implementing any of the following alternate modes of operation: firing of the HRSG duct burner, power augmentation with steam injection, or both. Initial tests for emissions from the combustion turbine shall be conducted for carbon monoxide, nitrogen oxides, volatile organic compounds, and visible emissions separately for each alternate mode of operation. In addition, NOx emissions of the inlet to, and the outlet from, the duct burner shall be tested. Initial performance test data shall also be converted into the units of the corresponding NSPS Subparts Db and GG emissions standards to demonstrate compliance (see Appendix E and F). [Rule 62-297.310(7)(a)1., F.A.C.]

26. Annual Performance Tests: Annual performance tests for carbon monoxide, nitrogen oxides and visible emissions from the combustion turbine shall be conducted separately for each applicable mode of operation. Tests required on an annual basis shall be conducted at least once during each federal fiscal year (October 1st to September 30th). When conducted at permitted capacity, the annual NOx continuous monitor RATA required pursuant to 40 CFR 75 may be substituted for the annual compliance stack test. [Rule 62-297.310(7)(a)4., F.A.C.]

27. Tests Prior to Permit Renewal: During the federal fiscal year (October 1st to September 30th) prior to renewing the air operation permit, the permittee shall also conduct performance tests for volatile organic compounds for each alternate mode of operation. [Rule 62-297.310(7)(a)3., F.A.C.]

28. Tests After Substantial Modifications: All performance tests required for initial startup shall be conducted after any substantial modification and appropriate shake down period of air pollution control equipment including the replacement of dry low-NOx combustors, installation of SCR or installation of an oxidation catalyst. Shake down periods shall not exceed 100 days after re-starting the combustion turbine. [Rule 62-297.310(7)(a)4., F.A.C.]

29. Testing Modes of Operation: The permittee shall conduct all required tests for each mode of operation defined below.

    (a) **Standard Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas as well as low sulfur distillate oil.

    (b) **Alternate Modes of Operation**: Separate tests shall be conducted when firing the combustion turbine with natural gas and implementing any of the following alternate modes of operation: firing of the HRSG duct burner, power augmentation with steam injection, or both. Hourly rates for HRSG duct firing (mmBTU) and steam injection for power augmentation (pounds of steam) shall be restricted to the rates that demonstrated compliance during the test for each alternate mode of operation. Note: Alternate modes of operation are not allowed when firing low sulfur oil.

    [Rule 62-4.070(3), F.A.C.]

30. NOx CEM: To demonstrate continuous compliance with the BACT emissions limits for nitrogen oxides (NOx), the owner or operator shall install, calibrate, operate, and maintain a continuous emission monitoring systems (CEMS) to measure and record the NOx and oxygen concentrations in the combustion turbine exhaust gas for each stack. Alternatively, a monitor for carbon dioxide

may be used in place of the oxygen monitor, but the system shall be capable of correcting the emissions to 15% oxygen.

Compliance with the 3/24-hour block averages for NOx emissions standards shall be demonstrated by continuous emissions monitoring data. A 3/24-hour block average shall be determined by calculating the arithmetic average of all hourly emission rates for the respective averaging period. Each 1-hour average shall be expressed in units of ppmvd corrected to 15% oxygen and calculated using at least two valid data points at least 15 minutes apart. When NOx monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified averaging period.

Continuous emission monitoring data required by this permit shall be collected and recorded during all periods of operation including startup, shutdown, and malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. Although recorded, emissions during periods of startup, shutdown and malfunction are subject to the excess emission conditions specified in this permit.

The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of: Rule 62-297.520, F.A.C., including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications 2 and 3; 40 CFR 60.7(a)(5); 40 CFR 60.13; 40 CFR 60, Appendix F; and 40 CFR Part 75. A monitoring plan 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. The plan shall consist of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location.

When the CEMS reports NOx emissions in excess of the standards allowed by this permit, the owner or operator shall notify the Compliance Authorities within one (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. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7].

31. Alternate Monitoring Plan: Subject to EPA approval, the following alternate monitoring may be used to demonstrate compliance.

(a) The NOx CEM data may be used in lieu of the monitoring system for water-to-fuel ratio and the reporting of excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG. Subject to EPA approval, the calibration of the water-to-fuel ratio-monitoring device required in 40 CFR 60.335(c)(2) will be replaced by the 40 CFR 75 certification tests of the NOx CEMS.

(b) The NOx CEM data shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG.

(c) 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 Authorized Representative, that commits to using a primary fuel of pipeline supplied natural gas containing no more than 1 grain of sulfur per 100 SCF of gas 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).

(d) Upon request from DEP, the CEMS emission rates for NOx on this unit shall be corrected to ISO conditions to demonstrate compliance with the NOx standard established in 40 CFR 60.332.

[40 CFR 60, Subparts Db and GG, Applicant Request]

32. Fuel Records: The permittee shall maintain on file a fuel purchase contract and typical analysis indicating the sulfur and nitrogen content of the natural gas being supplied. For all bulk shipments of low sulfur distillate oil received at this facility, the permittee shall obtain from the fuel vendor an analysis indicating the sulfur and nitrogen content. The analysis shall also specify the methods by which sulfur and nitrogen contents were determined and shall comply with the requirements of 40 CFR 60.335(d). [Rule 62-4.160(15), F.A.C.]

33. Daily Operations Log: Before the end of the following calendar day, the owner or operator shall record the following information in a written log for the previous day of operation: total hours of combustion turbine operation; hours of duct firing; hours of power augmentation; highest hourly rate of steam injected for power augmentation; highest hourly power production from HRSG in MW; highest level of ammonia slip in ppm; and the average water injection rate during oil firing in pounds per hour. [Rule 62-4.160(15), F.A.C.]

34. Monthly Operations Summary: By the fifth calendar day of each month, the owner or operator shall record the following information in a written log for the previous month of operation: hours of combustion turbine operation for gas/oil firing; hours of duct firing; hours of steam injection for power augmentation; million cubic feet of natural gas fired in the combustion turbine; gallons of low sulfur distillate oil fired in the combustion turbine; and the million cubic feet of natural gas fired in the HRSG duct burner. Totals for the previous month of operation and the previous 12 months of operation shall be recorded. In addition, the owner or operator shall calculate and record the following monthly averages: heat input to the combustion turbine from natural gas in mmBTU per hour; heat input to the combustion turbine from low sulfur distillate oil in mmBTU per hour; heat input to the duct burner from natural gas in mmBTU per hour [Rule 62-4.160(15), F.A.C.]

SECTION IV.

APPENDIX A - TERMINOLOGY

ABBREVIATIONS AND ACRONYMS

°F	-	Degrees Fahrenheit
DEP	-	State of Florida, Department of Environmental Protection
DARM	-	Division of Air Resource Management
EPA	-	United States Environmental Protection Agency
F.A.C.	-	Florida Administrative Code
F.S.	-	Florida Statute
SOA	-	Specific Operating Agreement
UTM	-	Universal Transverse Mercator
CT	-	Combustion Turbine
DB	-	Duct Burner
HRSG	-	Heat Recovery Steam Generator
DLN	-	Dry Low-NOx Combustion Technology
SCR	-	Selective Catalytic Reduction
OC	-	Oxidation Catalyst Technology for CO Control

RULE CITATIONS

The following examples illustrate the methods used in this permit to abbreviate and cite the references of rules, regulations, permit numbers, and identification numbers.

Florida Administrative Code (F.A.C.) Rules:

Example:	**[Rule 62-213.205, F.A.C.]**	
Where:	62	- refers to Title 62 of the Florida Administrative Code (F.A.C.)
	62-213	- refers to Chapter 62-213, F.A.C.
	62-213.205	- refers to Rule 62-213.205, F.A.C.

Facility Identification (ID) Number:

Example:	Facility ID No. 099-0001	
Where:	099	- 3 digit number indicates that the facility is located in Palm Beach County
	0221	- 4 digit number assigned by state database identifies specific facility

New Permit Numbers:

Example:	Permit No. 099-2222-001-AC or 099-2222-001-AV	
Where:	AC	- identifies permit as an Air Construction Permit
	AV	- identifies permit as a Title V Major Source Air Operation Permit
	099	- 3 digit number indicates that the facility is located in Palm Beach County
	2222	- 4 digit number identifies a specific facility
	001	- 3 digit sequential number identifies a specific permit project

Old Permit Numbers:

Example:	Permit No. AC50-123456 or AO50-123456	
Where:	AC	- identifies permit as an Air Construction Permit
	AO	- identifies permit as an Air Operation Permit
	123456	- 6 digit sequential number identifies a specific permit project

APPENDIX B - CONSTRUCTION PERMIT GENERAL CONDITIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

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

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

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

G.13 This permit also constitutes:

(a) Determination of Best Available Control Technology (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.

AIR PERMIT NO. 099-0568-001-AC / PSD-FL-266

LAKE WORTH GENERATION, L.L.C.
Palm Beach County, Florida

1.0 PROJECT DESCRIPTION

The applicant, Lake Worth Generation, L.L.C. (LWG), proposes to install and operate a new combustion gas turbine to be located at 117 College Street in Lake Worth, Palm Beach County, Florida. The City of Lake Worth owns and operates the existing Tom G. Smith Power Plant located on this same site. LWG will enter into a long-term lease of this property from the City of Lake Worth for independent operation of this new combustion turbine as a separate facility. Employees of the existing power plant will be used to operate and maintain the new combustion gas turbine. The combustion turbine will operate a significant amount of time in the simple cycle mode. When requested by the Tom G. Smith Power Plant, the combustion turbine will enter a combined cycle mode. The power plant will purchase this steam as a high priority when it is available and when there is a sufficient demand.

The new combustion gas turbine with electrical generator (Emissions Unit 001) specified in the application is a General Electric Frame 7FA, Model No. PG7241(FA)CT. An absorption chiller system will pre-cool the inlet air to the combustion turbine to a nominal 55°F to increase the mass of the compressor inlet air and resulting power output. The GE Frame 7FA incorporates dry, low NOx (DLN) technology to reduce nitrogen oxides while maintaining low levels of carbon monoxide. This technology involves the premixing of natural gas with combustion air to provide a lean mix with staged combustion. In simple cycle mode, the combustion turbine produces only direct electrical power up to a maximum of 176 MW when burning natural gas (primary fuel) and up to 186 MW when firing low sulfur distillate oil (backup fuel - 750 hours). The project also includes a heat recovery steam generator (HRSG) capable of providing enough steam to the existing Tom G. Smith Power Plant to produce up to an additional 74 MW of power. Midway through the application process, the applicant also requested the Department to consider a 175 mmBTU per hour natural gas-fired duct burner for the HRSG (Emissions Unit 002) to increase the steam generating capacity.

2.0 APPLICATION PROCESSING SCHEDULE

03/15/99	Department received a PSD air permit application.
04/09/99	Department mailed a request for additional information.
04/16/99	Comments from NPS on modeling analysis and BACT determination
04/22/99	Al Linero and Jeff Koerner performed a site inspection of the proposed location of the combustion turbine for the Department.
05/04/99	Department received additional information from the applicant with request to modify.
05/24/99	Department received additional and revised project information from the applicant.
06/08/99	The Department met with the applicant's engineer to clarify remaining questions.
06/21/99	The Department received comments from the NPS concerning the BACT determination.

3.0 PSD APPLICABILITY REVIEW

This project is to be located in Palm Beach County, an area that is currently in attainment for all air pollutants subject to a National Ambient Air Quality Standard (AAQS). A project is subject to review for the Prevention of Significant Deterioration (PSD) if it emits:

- 250 tons per year or more of any regulated air pollutant, OR
- 100 tons per year or more of any regulated air pollutant and it falls under one of the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C.

Pollutant emissions exceeding either of these thresholds are considered "major" and the applicant must employ the Best Available Control Technology (BACT) to reduce emissions. This project is major because it emits more than 250 tons of NOx per year. Once a project is considered to be a PSD major source for one pollutant, the other regulated pollutants are reviewed for PSD applicability based on lower thresholds known as Significant Emission Rates (Table 212.400-2, F.A.C.). Pollutant emissions exceeding these rates are considered "significant" and the applicant must also employ the Best Available Control Technology (BACT) to minimize emissions of each significant pollutant. The following table summarizes the potential to emit pollutants for this new project.

Pollutant	Emissions Rate In Tons Per Year			(M)ajor or (S)ignifcant	Subject To BACT?
	Project Potential Emissions[a,b]	Major Emissions Threshold	Significant Emissions Rate		
CO	204 (201)	NA	100	S	Y
NOx	438 (401)	250	40	M	Y
PM / PM10	43 (42)	NA	25 / 15	S	Y
SAM	11 (8)	NA	7	S	Y
SO2	70 (50)	NA	40	S	Y
VOC	39 (38)	NA	40	N	N

Table Notes:

a - Original application based worst case of 7760 hours of gas firing and 1000 hours of oil firing.

b - The final potential emissions are given in parentheses and are based on the draft permit limiting oil firing to an equivalent of 750 hours per year and 0.04% sulfur by weight.

Therefore, the proposed combustion turbine is a PSD major project for nitrogen oxides (NO_x) and carbon monoxide and will also have significant emissions of particulate matter (PM / PM_{10}), sulfuric acid mist (SAM), sulfur dioxide (SO_2). Each of these pollutants will require a determination of Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C. Potential VOC emissions were 39.2 tons per year, which is only slightly below the significant emissions rate of 40 tons per year and not subject to a BACT determination. However, an analysis for VOC emissions is also included for completeness in the BACT review. Detailed descriptions of the project, air quality impacts, and rule applicability are given in the Technical Evaluation and Preliminary Determination accompanying the Department's Notice of Intent to Issue Permit prepared for the applicant.

4.0 BACT DETERMINATION PROCEDURE

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction for each pollutant emitted that the Department determines is achievable through application of production processes and available methods, systems, and techniques for control of each such pollutant. The Department's determination is made on a case-by-case basis for each proposed project and takes into account energy, environmental and economic impacts. In addition, Rule 62-212.400(6)(a), F.A.C., states that in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169 of the Clean Air Act, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).
- 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 directs that BACT should be determined using the "top-down" approach. In this approach, available control technologies are ranked in order of control effectiveness for the emissions unit under review. The most stringent control option is evaluated first and selected as BACT unless it is technically infeasible for the proposed project or rejected due to adverse energy, environmental or economic impacts. If the control option is eliminated, the next most stringent alternative is considered. This top-down approach continues until BACT is determined.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls; and select BACT. The EPA directs that a BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants). In addition to the information submitted by the applicant, the Department may rely upon other available information in making its BACT determination.

The Department will consider the control or reduction of "non-regulated" air pollutants when determining the BACT limit for regulated pollutants, and will weigh control of non-regulated air pollutants favorably when considering control technologies for regulated pollutants. The Department will also favorably consider control technologies that utilize pollution prevention strategies. These approaches are consistent with EPA's consideration of environmental impacts.

For this project, there are no applicable NESHAP regulations, however, the following emissions units are subject to the New Source Performance Standards (NSPS) of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C.

Subpart GG: Stationary Gas Turbines

Subpart Db: Industrial-Commercial-Institutional Steam Generating Units (HRSG Duct Burner)

5.0 BACT ANALYSES AND DETERMINATIONS

For this project, the PSD pollutants of concern are CO, NO_X, PM, PM_{10}, SAM, and SO_2 and will require BACT determinations. Although potential VOC emissions are below the significant emissions rate, an analysis for VOC emissions is also included for completeness. The applicant proposed control strategies for these pollutants for the combustion turbine and duct burner. The applicant's proposal and the

Department's BACT determination for each pollutant and emissions unit are discussed below. Besides the information submitted by the applicant, the Department also used the following information:

- Comments from the National Park Service dated 4/16/99 and 6/21/99
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document – NOx Emissions from Stationary Gas Turbines
- Goal Line Environmental Technology Website: http://www.glet.com
- General Electric technical product literature

The potential emissions from the combustion turbine are more than an order of magnitude greater than the potential emissions from the duct burner. Therefore, the BACT determination for the gas turbine is discussed in detail followed by a short summary for the duct burner.

5.1 NITROGEN OXIDES

During combustion, nitrogen oxides form as a result of dissociation of molecular nitrogen and oxygen in the fuel and combustion air and subsequent recombination into various oxides of nitrogen (NOx). *Thermal* NOx forms in the high temperature areas of a combustion process, increases exponentially with increasing flame temperature, and increases linearly with increasing residence time. *Fuel* NOx is formed when burning fuels containing chemically bound nitrogen. This mechanism is almost negligible when combusting natural gas and higher-quality distillate oils due to inherently low concentrations of fuel-bound nitrogen.

For a gas turbine, the hot combustion gases are diluted with additional air from the compressor section and directed to the turbine section at temperatures up to 2350°F. During simple cycle operation, electrical power is produced directly from the hot expanding exhaust gases in the form of shaft horsepower. Gas turbine loads and ambient conditions may also increase flame temperatures resulting in higher NOx emissions. Uncontrolled NOx emissions from conventional combustion turbines may range as high as 100-600 parts per million by volume, on a dry basis, corrected to 15 percent oxygen. Therefore, inhibiting the formation of NOx emissions depends primarily on reducing the flame temperature and the exposure time of combustion gases to this temperature.

5.1.1 Range of BACT Limits

In the top-down BACT approach, the control technologies capable of obtaining the lowest achievable pollutant emissions are placed on top. The lowest-emitting, technically feasible control option is selected as BACT unless it would result in significant adverse energy, environmental, and energy impacts. Therefore, EPA and state determinations of the Lowest Achievable Emission Rate (LAER) for nonattainment areas provide a reasonable "ceiling" for making a BACT determination. Likewise, EPA stresses that BACT shall not be less stringent than any applicable standards imposed by a NESHAP nor NSPS. So, a NESHAP or NSPS establishes the "floor' for making a BACT determination.

The "ceiling" for making this BACT determination appears to be one of several add-on control technologies, such as SCR, that reduces NOx emissions down to the range of 3.5 ppmvd @ 15% oxygen. This level represents several previous BACT as well as many LAER determinations. There are no applicable NESHAP regulations, however, the floor for making this BACT determination would be the New Source Performance Standards (NSPS) in 40 CFR 60, Subpart GG for Stationary Gas Turbines. The Department adopted this NSPS regulation by reference in Rule 62-204.800, F.A.C. The NOx emissions standard is 75 ppmvd @ 15% oxygen, corrected for fuel nitrogen content, turbine heat rate, and ISO conditions or approximately 110 ppmvd @ 15% oxygen for gas/oil firing with negligible fuel nitrogen. The following tables summarize recent technology determinations as well as proposed determinations for several current combined cycle projects.

SUMMARY OF RECENT BACT DETERMINATIONS FOR SIMILAR PROJECTS

Project Location	Power Output and Duty	NOx Limit ppm @ 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 ppm NOx limit on gas
Mid-GA Cogen	308 MW CC CON	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW WH 501D5A CTs
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 ppm by SCR/SNCR if DLN fails
FPC Hines-Polk, FL	485 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW WH 501FC CTs Installed temporary SCR system
Tallahassee, FL	260 MW CC CON	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS7231FA CT DLN guarantee is 9 ppm
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 7FA CTs

CC = Combined Cycle
DB = Duct Burner
NG = Natural Gas
CT = Combustion Turbine
SNCR= Selective Non-catalytic Reduction
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

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Lakeland, FL	25 - NG or 10 by Ox Cat 75 - FO @ 15% O_2	4 - NG 10 - FO	10% Opacity	Clean Fuels Good Combustion
Mid-GA Cogen,	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
Fort Myers, FL	12 - NG @15% O_2	1.4 - NG	10% Opacity	Clean Fuels Good Combustion
Santa Rosa, FL	9 - NG (CT) 24 - NG (CT&DB)	1.4 - NG (CT) 8 - NG (CT&DB)	10% Opacity	Clean Fuels Good Combustion
FPC Hines-Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG		10% Opacity	Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Barry, AL	0.034 lb/mmBtu - NG/CT 0.057 lb/mmBtu - CT/DB	0.015 lb/mmBtu After CT and DB	0.011 lb/mmBtu - CT/DB 10% Opacity	Clean Fuels Good Combustion

COMBINED CYCLE TURBINE PROJECTS - PERMITS PENDING OR NOT YET IN RBLC DATABASE*

Project Location	MW	NOx Limit Gas/Oil	Technology	
AL Pwr – Theodore, AL	210	3.5		SCR
Androscoggin Energy, ME	3x50	6.0		SCR
ARCO Watson, CA	45	5.0		SCR
Bridgeport Energy		6.0		SCR
Calpine – S. Point, AZ	500	3.0		SCR
Casco Bay, ME	520	5.0		SCR
Cogen, Tech Linden, NJ	581	3.5		SCR
Desert Basin, AZ		4.5		SCR
Dighton, MA		3.5		SCR
Duke New Smyrna, FL	2x165	9.0	DLN	
Enron (LAER), CA		2.5		SCR
FPC Hines, FL	2x165	6.0		SCR
FPC Polk, FL				SCR
Frontera Power, TX	330	15.0	DLN	
Griffith Energy, AZ	650	3.0		SCR
HDPP (LAER), CA		3.0		SCR
Hermiston Generating, CA		4.5		SCR
High Desert Power, CA		9.0/2.5	DLN	SCR
Kissimmee CI#3, FL	167	9.0/42.0 4.5/15.0	DLN	SCR
Lakeland, FL	350	7.5/15.0		SCR
Lake Worth Generating, FL	186+74	9.0/42.0	DLN	
LaPoloma, CA	4x262	3.0		SCR
Miss. Power – Daniels, MI	170	3.5		SCR
NW Regional Power, WA	4x210	9.0	DLN	
Orange Gen. – Bartow, FL	2x42	15.0	DLN	
Rotterdam, NY		4.5		SCR
Sacremento Power, CA	115	3.0		SCR
Sumas, WA	2x350	9.0	DLN	
Sutter,	170	3.5		SCR
TX-NM Pwr – Lordsburg	2x40	15.0/25.0	DLN	
Theodore Cogen,		3.5		SCR
Three Mtn. Power, CA	500	2.5		SCR
Tiverton, RI	500	3.5		SCR

Note: The NOx limits are in units of ppmvd @ 15% O2.

*The National Park Services provided most of this data.

5.1.2 Applicant's Proposed NOx BACT

The applicant proposed the following control technologies and emissions standards as BACT for NOx emissions:

> NOx emissions from the combustion turbine shall be controlled by dry low-NOx combustion technology when firing natural gas and water injection when firing low sulfur distillate oil. NOx emissions shall not exceed 9.0/42.0 ppmvd @ 15% oxygen for gas/oil firing.

In making this proposal, the applicant researched numerous control technologies resulting in a variety of emission reductions. The following discussion summarizes each control option reviewed as well as any reasons for rejecting it as BACT.

- Wet Injection: The injection of water or steam into the combustion process inhibits NOx formation by quenching the flame temperature. This option is a demonstrated technology, is frequently used to control NOx emissions from gas turbines, and formed the basis for the original NSPS emissions limits. Wet injection may result in higher CO emissions and appears to have practical limits of about 25/42 ppmvd @ 15% oxygen for gas/oil firing.
- Selective Catalytic Reduction (SCR): This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed and combines with the NOx to form nitrogen and water. The temperature requirement is between 450° F and 850° F which is within the range of the exhaust gases during combined cycle operation. Very low emissions of NOx are achievable (< 3.5 ppmvd). Because this project includes a HRSG, exhaust gas temperatures will be in an acceptable range. SCR is a commercially available, demonstrated control technology currently employed on many combined cycle combustion turbine projects of this type. High temperature catalysts are also available for "hot" SCR (>850° F) at much greater costs. (Although this project may have significant simple cycle operation, the emission levels from the dry low-NOx technology for this model gas turbine are representative of current BACT determinations for simple cycle operation. In general, hot SCR is much more costly than conventional SCR and would not be economically feasible. Conventional SCR will be reviewed as if the unit operated in combined cycle mode 100%.)
- Dry Low-NOx (DLN) Combustor Technology: Many manufacturers now offer integral dry low-NOx lean, premix combustor technology that inhibits NOx formation by reducing the flame temperature. This is achieved by premixing fuel with air prior to combustion, operating in a fuel-lean mode, and staging combustion. To respond to variety of startup and load conditions, the DLN combustors are capable of producing diffusion, piloted premix, and premix flames, as well as combinations. There are 14 can-annular DLN 2.6 combustors in the General Electric Frame 7FA combustion turbine designed to provide single-digit NOx concentrations. Fuel flow distributions are a function of the combustion temperature and are adjusted by an automated control system. DLN units are available with NOx emissions of less than 25 ppmvd @ 15% oxygen with some units capable of single-digit NOx emissions at loads of 50% to 100%.
- SCONOx: This is an add-on control technology for reducing both CO and NOx exclusively offered by Goal Line Environmental Technologies. Specialized potassium carbonate catalyst beds reduce CO and NOx emissions using an oxidation/absorption/regeneration cycle. Operation is limited to temperatures between 300°F and 700°F which requires a HRSG for use with a gas turbine. *Although this control option may be technically feasible, it is rejected as an emerging technology with limited commercial availability and unknown applicability to larger "F" class turbines.*

- NOxOUT: This is a selective catalytic reduction process that injects urea to reduce NOx emissions. This process requires a temperature range of 1600°F to 1900°F to be effective. The combustion turbine exhaust gases will reach a maximum temperature of only 1100°F during simple cycle operation. *This control option is rejected as technically infeasible.*
- Thermal DeNOx: This is a high temperature selective noncatalytic reduction (SNCR) process using ammonia as the reducing agent. This process requires an exhaust gas stream exceeding a temperature of 1800°F. The use of ammonia plus hydrogen can lower the temperature requirement to 1000°F, but commercial applications have been limited only to heavy industrial boilers and large furnaces. *This control option is rejected as being technically infeasible.*
- XONON™: XONON™ works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The result is partial combustion with a lower temperature and NOx formation followed by flame-less catalytic combustion to further inhibit NOx formation. The technology has been demonstrated on only a few gas turbines that are much smaller than the proposed project. However, General Electric 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™ is rejected as an emerging technology that has not been demonstrated for this size gas turbine.*
- Nonselective Catalytic Reduction (NSCR): This control option also utilizes a catalyst to reduce NOx emissions from exhaust gas streams with a low oxygen content and within a temperature range of 700°F to 1400 °F. This technology has been applied to reciprocating engines, but exhaust gases from combustion turbines generally exceed 12% oxygen that is too high for NSCR. *This control option is rejected as being technically infeasible.*

The remaining technically feasible and commercially available control alternatives are ranked below in the following table from most effective to least effective.

Control Alternative	Fuel	Controlled Emissions ppmvd, @ 15% O_2	Control Efficiency	Reduction TPY	Totals TPY
1a. SCR w/ammonia	Gas	3.5	61% [a]	157	267
1b. SCR w/ammonia	Oil	16	61% [b]	110	
2a. DLN Technology	Gas	9.0	Baseline	NA	NA
2b. DLN W/Wet Injection	Oil	42.0	Baseline	NA	

Table Notes:

a Based on emissions control from DLN BACT level to SCR BACT level.

b When using SCR for oil firing, the applicant assumed a control efficiency of 61%, as was the case for firing natural gas.

Installing selective catalytic reduction (SCR) with ammonia injection as BACT for this project would result in an overall NOx reduction of 267 tons per year. The applicant reviewed SCR for the following additional adverse impacts.

Energy Impacts: Installation of SCR would result in an energy penalty due to the pressure drop across the catalyst bed of nearly 2.5 inches of water or 7.7 million kWh per year of potential lost generation.

The SCR equipment requires about 0.71 million kWh per year of energy to operate. This results in a total energy loss of 8.4 million kWh per year or the equivalent of 700 residential customers.

Economic Impacts: The applicant estimates the incremental, annualized cost of SCR over DLN technology alone to be nearly $8100 per ton of NOx removed based on 100% base load operation. These costs are the result of substantial costs related to installation, equipment, catalyst replacement, energy consumption, and ammonia usage. Costs for ammonia are high because the nearest ammonia supplier is located in Tampa and ammonia would be transported brought by truck to the plant.

Environmental Impacts: SCR requires the injection of ammonia at slightly above the stoichiometric rate which inevitably results in ammonia "slip" or emissions of unreacted ammonia. It is likely that as much as 5 ppm of ammonia would slip by without reaction and, as the catalyst ages, as much as 10 ppm. At 5-10 ppm of ammonia slip, nearly 70-140 tons per year of ammonia could be emitted. In addition, ammonia may react with sulfur to generate up to an additional 22 tons per year of PM_{10} in the form of ammonium sulfates and bisulfates. Because catalysts typically contain vanadium pentoxide, handling and disposal of spent catalysts is subject to the RCRA regulation for hazardous chemical wastes.

Based on the energy, economic, and environmental impacts, the applicant rejected SCR and selected DLN technology as BACT (9/42 ppmvd @ 15% O_2 For gas/oil firing).

5.1.3 NPS Comments Dated June 21, 1999

On June 21,1999, the Department received eleven pages of comments regarding the AQRV analysis and the BACT determination for this project. The applicant satisfied concerns regarding the AQRV analysis. However, the majority of the comments centered on the applicant's discretionary use of the OAQPS Cost Manual recommendations and possibly excessive estimates. Summarizing, NPS asserted that many of the costs calculated by the applicant were inflated to make SCR look overwhelmingly expensive. NPS also included its own cost estimate using the OAQPS Cost Manual to arrive at a cost of nearly $4000 per ton of NOx removed. Also included was a list of combined cycle turbine projects for pending permits or projects not available on EPA's RBLC database. NPS expressed concern that similar projects should use similar controls unless there are unusual circumstances. NPS does not believe that the applicant has shown SCR to be cost prohibitive nor cause adverse environmental impacts. The Department will respond to these comments in the following discussion of the Department's BACT determination.

5.1.4 Department's NOx BACT Determination

In general, the Department concurs with the applicant's proposed BACT of dry low-NOx combustion technology to control NOx emissions. The installation of SCR presents an unreasonable additional cost given this specific combustion turbine model's proven capability to meet single-digit NOx emission levels. In addition, the location of the proposed project in relation to other nearby properties would increase the expected risk related to an ammonia spill due to transportation, unloading, and storage. The following summarizes the Department's rationale:

(1) The Department does believe the applicant's estimated cost of $8100 per ton of NOx removal to be high compared to other similar projects, as pointed out by the NPS. Several of the estimated costs appear high, particularly treating the catalyst as a recurring direct capital cost which also increases the direct installation costs. Also, as NPS stated, there are three different "10% contingency" estimates for the indirect capital costs, the direct annual costs, and the annual energy costs. The Department performed a cost estimate based on the NPS estimate eliminating many of the disputed costs, except for the following items:

- Used applicant's HRSG modification cost based on vendor quote.
- Used applicant's ammonia storage cost based on vendor quote.

- Included applicant's cost for preparing a Risk Management Plan for ammonia.
- Used applicant's operator labor and supervisor costs that appeared more realistic.
- Used applicant's catalyst disposal cost and catalyst replacement cost (guaranteed 3-year life) based on vendor quotes.
- Used applicant's estimate of total ammonia costs. (NPS may not be aware that Florida has an anhydrous ammonia pipeline from the west coast in Tampa that terminates in central Florida. Similar combustion turbine projects in Lakeland and Polk County would benefit from this system, but Lake Worth is located on the east coast and would not. From conversations with other consulting engineers, the Lakeland and Polk projects estimated approximately $360/ton for ammonia. The cost of hauling ammonia to the east coast by truck would be significant. However, the Department also believed the applicant's quoted estimate for ammonia of $700/ton to be high and calculated a total cost using $500/ton and the NPS estimate for ammonia usage. However, this total cost exceeded the applicant's estimated total cost for ammonia usage, so the applicant's original estimate was used.)
- Included applicant's cost estimate for "capacity lost" as separate from the heat rate penalty because this facility will be under contract to provide not only energy, but also capacity including availability.

Many of the other OAQPS costs methods are based on a percentage of one or more of these costs, such as taxes, installation costs, engineering, performance tests, etc. Assuming the capital recovery factor of 7%, the Department roughly estimates the cost of SCR to be $5500 per ton of NOx removed. This appears to fall within the range of similar projects located in Florida ($4000 to $6500 per ton). However, the Department believes that installation of SCR for this project is not quite cost effective given the already low NOx emissions characteristics for this specific model of combustion turbine.

(2) The NPS provided a table of 33 combined cycle turbine projects that are pending or not yet in the RBLC database. Nine of these are controlling NOx emission with DLN technology alone, and the remaining 25 are installing SCR.

- Of the 25 projects designed with SCR, eight are located in California, a state noted for its serious ozone problems. Many of the determinations from California represent LAER, a regulatory determination that does not consider the economy of control options. By state law, BACT in California is most likely LAER in the rest of the country.
- Of the remaining 25 projects specifying SCR, five projects have emissions levels of 6.0 ppmvd @ 15% oxygen or greater. This is most likely due to the use of a higher-emitting gas turbine. It seems reasonable to conclude that reducing NOx levels from 9.0 ppmvd to 6.0 or 7.5 ppmvd would not be cost effective. In addition, actual operational data for the specified GE Frame 7FA indicates actual NOX emissions of 6 to 8 ppmvd, very close to these SCR-controlled limits.
- Another eight of the 25 projects are located in ozone transport regions that have the potential to impact other states. Florida is not identified as a contributor to ozone transport.

This table clearly shows that in many areas of the country, SCR is economical and being installed for a variety of reasons, some of which are not related to a BACT determination. It also indicates that, for the most recent projects being permitted, 9.0 ppmvd @ 15% oxygen is currently the lowest achievable emission level with dry low-NOx combustion technology for "F" class turbines.

(3) Because of the site-specific conditions of the proposed location, the Department also believes consideration should be given to the environmental impacts of injecting aqueous ammonia and the additional related risks of transporting, unloading, and storing. Ammonia is an air toxic and would be emitted as unreacted ammonia "slipping" past the catalyst. Too much ammonia is undesirable and may be an indicator that catalyst is approaching its useful life. However, some ammonia slip is necessary to ensure the highest possible removal of NOx. Approximately 30 to 70 tons per year of ammonia would be emitted as a result of 5 ppm of slip. Although this represents a significant amount of pollutant emissions, it is also an indicator of just how much ammonia is required to be transported, unloaded, and stored to achieve the additional NOx reductions. The Department estimates this quantity to be roughly 1000 tons (250,000 gallons) of aqueous ammonia per year. Although the risk associated with aqueous ammonia is *much less* than anhydrous ammonia, the amount of ammonia required would require the submittal of a Risk Management Plan to EPA, indicating there is *some* risk associated with its use. This increased risk is compounded considering the proposed site's proximity to the following: Interstate I-95 (less than 50 yards to the west); a well field operated by the City of Lake Worth at the collocated Tom G. Smith Plant; a large high school (less than 200 yards to the north); a new public park (less than 100 yards to the east); a residential area in the immediate vicinity; a day care center just south across 6th Avenue South. The Department believes that these environmental impacts should weigh in making a BACT determination for this particular project.

(4) Consistent with EPA's policy regarding pollution prevention, the Department gives favorable consideration to inherently less polluting processes with similar levels of control. The analysis of this project considers SCR controlling a "clean" 9 ppmvd gas turbine down to 3.5 ppmvd. However, the permittee is less likely to secure a contract with the manufacturer to maintain NOX emissions at 9 ppmvd because control will be by SCR. In other words, the unit may not be tuned to the lowest possible emissions because emissions are controlled by add-on equipment. In addition, SCR results in additional ammonia emissions of up to 70 tons per year at 5 ppm of slip.

Although installation of selective catalytic reduction is technically feasible and commercially available, it is eliminated as a control alternative due to the energy, environmental, and economic impacts described above. The Department concurs with the applicant that the combustion design technology inherent in a properly tuned and maintained General Electric Frame 7FA combustion turbine represents BACT for nitrogen oxides for this project. Therefore, the BACT emission limiting standards shall not exceed:

Gas: 9.0 ppmvd @ 15.0% O_2, 3-hour test avg. (24-hour block continuous compliance)
Oil: 42.0 ppmvd @ 15.0% O_2, 3-hour test avg. (3-hour block continuous compliance)

This BACT determination is more stringent than the standards of NSPS, Subpart GG.

Compliance with the BACT emissions limiting standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 20. Compliance shall be demonstrated with separate performance tests conducted for the firing of natural gas as well as for the firing of low sulfur distillate oil. Thereafter, compliance with the standards shall be demonstrated with a continuous emissions monitor certified in accordance with EPA's performance specifications. As an alternative to the annual compliance test, the CEMs RATA results may be used demonstrate compliance as long as capacity, notice, reporting requirements for the annual test are met. All performance tests shall be conducted at 95% or more of the permitted capacity of the turbine.

5.2 CARBON MONOXIDE

5.2.1 Applicant's Proposed CO BACT

Emissions of carbon monoxide (CO) will result from incomplete fuel combustion while operating the gas turbine. The project will generate significant emissions of CO (> 100 tons per year) and must therefore apply the best available control technology (BACT). The applicant's review indicates two main control options that are technically feasible and commercially available for BACT: an oxidation catalyst and combustion design. This leads to the following simplified analysis.

Control Alternatives	Emissions (TPY)	Control Effectiveness(%)	Incremental Costs ($/ton)[a]	Incremental Costs ($/ton)[b]
Oxidation Catalyst	79	61.5%	$6104	$7600
Combustion Design	204	Baseline	Baseline	Baseline

Notes:

a *Based on annualized costs of $763,000 and a CO emissions reduction of 125 tons.*

b *Based on annualized costs of $950,000 and a CO emissions reduction of 125 tons. Higher costs consider a reduction in energy produced due to the loss of energy caused by the pressure drop across the catalyst bed.*

The following additional impacts were evaluated considering the selection of an oxidation catalyst as BACT for this project.

Energy Impacts: Installation of an oxidation catalyst would result in an energy penalty due to the pressure drop across the catalyst bed. The energy loss equates to approximately 30,000 mmBTU per year or nearly 30 million cubic feet of natural gas.

Environmental Impacts: The predicted 1-hour and 8-hour CO emission concentrations resulting solely from combustion design technology are 9 ug/m^3 and 3 ug/m^3, respectively. These concentrations are two orders of magnitude below the corresponding EPA Significant Impact Levels and three orders of magnitude below the corresponding Ambient Air Quality Standards. Further control by an oxidation catalyst would appear to have a negligible environmental benefit. Also, the installation and operation of an oxidation catalyst could result in almost 10 tons per year of additional fine particulate matter.

Economic Impacts: From the summary table above, addition of an oxidation catalyst would result in incremental costs between $6100 and $7600 per ton of additional pollutant removed.

5.2.2 Department's CO BACT Determination

Although installation of an oxidation catalyst is technically feasible and commercially available, it is eliminated as a control alternative due to the energy and economic impacts described above. The Department gives no weight to the applicant's argument that further reduction in CO emissions would have negligible ambient impacts. Ambient impacts are evaluated in the modeling analysis and are not considered in the BACT determination. The Department also believes the applicant's estimated costs to be high when compared to other similar projects. However, the Department concurs with the applicant that the combustion design technology inherent in the GE Frame 7FA combustion turbine represents BACT for carbon monoxide for this project. Therefore, the BACT emission limiting standards shall not exceed:

Gas: 12.0 ppmvd at 15% O_2, 3-hour test avg.
Oil: 20.0 ppmvd at 15% O_2, 3-hour test avg. (up to 750 hours)

Compliance with the BACT emissions limiting standards shall be demonstrated by conducting performance tests in accordance with EPA Method 10. For the initial compliance demonstration, separate performance tests shall be conducted for the firing of natural gas as well as for the firing of low sulfur distillate oil. Thereafter, performance tests shall be conducted at least annually. All performance tests shall be conducted at 95% or more of the permitted capacity of the turbine.

5.3 Particulate Matter, Sulfur Dioxide, and Sulfuric Acid Mist

Emissions of particulate matter, sulfur dioxide, and sulfuric acid mist will result from the combustion of the gas turbine fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in the fuel. Most of the particulate matter emitted from these types of processes will be less than 10 microns in diameter (PM_{10}). Similarly, emissions of sulfur dioxide and sulfuric acid mist are a function of the amount of fuel sulfur. Gas turbines are subject to the following New Source Performance Standards for sulfur dioxide in 40 CFR 60, Subpart GG:

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

5.3.1 Applicant's Proposed PM/PM_{10}, SAM, and SO2 BACT

The applicant's review of EPA's RACT/BACT/LAER Clearinghouse data indicates that BACT for combustion turbines for these pollutants are fuel specifications. Typically, BACT has been established as pipeline-grade natural gas (negligible sulfur) as the primary fuel and low sulfur (< 0.05% sulfur by weight) distillate oil as a backup fuel. In addition, for the GE Frame 7FA, General Electric guarantees particulate matter emissions of no more than 9 pounds per hour for natural gas firing and 17 pounds per hour for low sulfur distillate oil firing. This equates to less than 0.01 grains per dry standard cubic feet of exhaust gas or roughly the emissions concentrations *after* control by a baghouse. Because the estimated potential emissions already reflect current BACT emissions levels, a top-down BACT analysis was not performed. The applicant proposed BACT to be the advanced combustion design of the GE Frame 7FA combined with clean fuels.

5.3.2 Department's PM/PM_{10}, SAM, and SO2 BACT Determination

There appears to be little environmental benefit gained by the addition of control equipment to control already very low emissions of particulate matter, sulfur dioxide, and sulfuric acid mist. Annualized costs per ton of pollutant removed would be prohibitive. The specification of fuels containing low concentrations of sulfur constitutes a pollution prevention technique, is given favorable consideration by the Department, and remains consistent with EPA direction. Therefore, the Department agrees with the applicant and determines that the best available control technology (BACT) for particulate matter, sulfur dioxide, and sulfuric acid mist to be the following fuel specifications.

Natural Gas: The combustion turbine shall be fired primarily by pipeline natural gas containing no more than 1 grain of sulfur per 100 standard cubic foot of natural gas.

Distillate Oil: The combustion turbine may be fired with No. 2 (or a superior grade) distillate fuel oil containing no more than 0.04% sulfur by weight and for no than 750 hours per consecutive 12 month period.

Limiting the sulfur content of the fuels to the above levels clearly complies with the NSPS limits for sulfur dioxide. In addition, the Department will specify the following permit conditions for particulate matter:

Visible Emissions: As a surrogate for particulate matter, visible emissions shall not exceed 10% opacity.

Compliance with the fuel specification shall be demonstrated by keeping records of the sulfur contents of the fuels delivered. Initial compliance with the visible emissions standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Method 9. All performance tests shall be conducted at 95% or more of the permitted capacity of the turbine.

5.4 VOLATILE ORGANIC COMPOUNDS

The applicant calculated potential VOC emissions to be 39 tons per year, just below the significant emissions rate of 40 tons per year. Although a BACT determination is not required, the Department includes a discussion of VOC emissions because this level is so close to the significant emissions rate. Emissions of volatile organic compounds (VOC) are the result of incomplete fuel combustion and mostly dependent upon the combustion design. Because the combustion turbine is very efficient at destroying VOC, there are really no viable add-on control techniques. The applicant states that the maximum VOC levels are 3.5 ppmvw for firing natural gas and 7.0 ppmvw for firing low sulfur distillate oil, measured as methane.

Because the VOC levels are just below the threshold of the significant emissions rate, the Department will specify the maximum VOC levels as emissions limits.

Gas: 3.5 ppmvw measured as methane, 3-hour test avg.
Oil: 7.0 ppmvw measured as methane, 3-hour test avg.

Initial compliance with the VOC emissions limits shall be demonstrated by conducting performance tests in accordance with EPA Methods 18, 25, and 25A. Thereafter, compliance with the VOC emissions rates shall be assumed if compliance is demonstrated for the emissions standards for carbon monoxide and particulate matter. Compliance shall also be demonstrated during the fiscal year prior to renewing the operation permit.

5.5 HRSG DUCT BURNER AND POWER AUGMENTATION

During combined cycle operation, waste heat in the exhaust from the gas turbine is reclaimed as steam energy with a heat recovery steam generator (HRSG) and directed to the Tom G. Smith Power Plant's existing steam turbines to produce electrical energy. Midway through this project, the applicant requested the addition of a natural gas-fired supplemental duct burner (175 mmBTU per hour) to the HRSG to raise the combustion turbine exhaust temperature. The request also included the injection of steam for "power augmentation" to temporarily boost power production. Both of these requests result in an increase in CO and NOx emissions. The HRSG duct burner is subject to the New Source Performance Standards of 40 CFR 60, Subpart Db for Industrial-Commercial-Institutional Steam Generating Units, adopted by reference in Rule 62-204.800, F.A.C. This regulation limits NOx emissions to 0.20 lb/mmBTU or less of heat input for a duct burner on a combined cycle gas turbine.

In order to ensure that an increase in potential emissions would not result in changes to the ambient modeling analysis, the applicant also requested the flexibility to trade 2 hours of duct firing for one hour of allowable oil firing for up to 2000 hours per year. Duct firing under this scheme would only occur when firing natural gas in the combustion turbine. Emissions of all pollutants would increase when firing the primary fuel – natural gas.

5.5.1 Applicant's Proposed BACT

The applicant proposed the following control technologies and emissions standards as BACT:

> **CO**: 0.10 lb/mmBTU of heat input to the duct burner (20.0 pounds per hour), controlled with combustion design or 17.5 ppmvd @ 15% O_2 for total emissions including the gas turbine
>
> **NOx**: 0.10 lb/mmBTU of heat input to the duct burner (20.0 pounds per hour), controlled with low-NOx burners; for compliance demonstrated by the continuous NOx monitor, emissions shall not exceed 10.7 ppmvd @ 15% oxygen from the HRSG stack
>
> **PM/PM_{10}, SO_2, VOC**: controlled with clean fuels and good combustion techniques (The applicant identifies almost negligible contributions of these pollutants.

Note: The emissions from duct firing must be added to the emissions from the combustion turbine when firing natural gas.

5.5.2 Department's BACT Determination

The Department rejects the applicant's proposed BACT. The Department believes that the addition of the duct burner was requested to ensure steam production capacity would be available to support power augmentation during the hottest summer days. This is supported by the fact that the original project was submitted without power augmentation or duct firing and pre-application discussions that indicated perhaps only 60 MW of steam-generated capacity would be needed for the existing Tom G. Smith Power Plant. In other words, the Department believes that the combustion turbine, as originally proposed, is capable of producing enough steam to meet the needs of the Tom G. Smith Power Plant. In addition, trading operation when firing oil for these alternate modes of operation seems inappropriate. Oil generates much higher emissions and its limited use is allowed as a backup fuel. During a site visit, representatives of LWG indicated no interest in oil firing beyond its use as backup fuel.

As the applicant indicated, duct firing and power augmentation have the potential to increase CO and NOx emissions in excess of the clean, pollution-preventing technology described in the above BACT determinations for CO and NOx. The applicant rejected SCR and an oxidation catalyst primarily on the basis of excessive costs. In the requests for power augmentation and duct firing, the applicant is requesting higher emissions to ensure compliance during peak energy demands for economic reasons. The Department believes these alternate modes of operation *defeat* the arguments made for DLN technology if the facility is allowed to operate nearly 25% of the time (2000 hours per year) in excess of the CO and NOx BACT standards for the previously defined and inherently less polluting DLN technology.

Therefore, the Department will list duct firing and power augmentation as alternate operating modes of operation, provided the permittee is capable of compliance with the CO and NOx emissions standards specified for operation of the combustion turbine alone. In other words, no increases in maximum emissions are allowed. Power augmentation and duct firing shall be limited to 2000 hours per year. Further, the Department determines NOx BACT for the duct burner to be 0.08 lb of NOx per mmBTU of heat input to the duct burner. In addition, the permit will allow the permittee to select the following control options and more stringent standards if these modes of operation are desired and compliance with the DLN standards is not attainable.

> **CO**: The permittee may elect to install an oxidation catalyst to successfully include duct firing and power augmentation for this project. The following more stringent emissions standards shall apply with or without duct firing:
>
> Gas: 4.7 ppmvd @15% O_2, 3-hour test average

Oil: 7.8 ppmvd @15% O_2, 3-hour test average

NOx: The permittee may elect to install selective catalytic reduction using aqueous ammonia to successfully include duct firing and power augmentation for this project. The following more stringent emissions standards shall apply with or without duct firing:

Gas: 3.5 ppmvd @15% O_2, 3-hour test avg. (3-hour block for continuous compliance)
Oil: 16.4 ppmvd @15% O_2, 3-hour test avg. (3-hour block for continuous compliance)

Compliance with the BACT emissions limiting standards shall be demonstrated by conducting initial and annual performance tests in accordance with EPA Methods 10 and 20. Compliance shall be demonstrated with separate performance tests conducted for the firing of natural gas as well as for the firing of low sulfur distillate oil. Thereafter, compliance with the NOx standards shall be demonstrated with a continuous emission monitor certified in accordance with EPA's performance specifications. As an alternative to the annual compliance test, the CEMs RATA results may be used demonstrate compliance as long as capacity, notice, reporting requirements for the annual test are met. In addition, power augmentation and duct firing shall be limited to the rates of operation during compliance testing. All performance tests shall be conducted at 95% or more of the permitted capacity of the turbine.

6.0 SUMMARY OF DEPARTMENT'S BACT DETERMINATION

6.1 BACT Emission Limits

Following are the BACT limits determined by the Department for this project. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, will be given in the specific conditions of the permit.

Pollutant	Mode of Operation/Controls*	Emission Standard
EU-001/002: Combustion Turbine and HRSG With or Without Duct Firing		
CO	Simple or Combined Cycle / DLN (Gas)	12.0 ppmvd @ 15% O_2, 3-hour avg. 43.2 pounds per hour
	Simple or Combined Cycle / Wet Injection (Oil)	20.0 ppmvd @ 15% O_2, 3-hour avg. 73.4 pounds per hour
	Combined Cycle / Oxidation Catalyst Option (Gas)	4.7 ppmvd @ 15% O_2, 3-hour avg. 16.8 pounds per hour
	Combined Cycle / Oxidation Catalyst Option (Oil)	7.8 ppmvd @ 15% O_2, 3-hour avg. 28.6 pounds per hour
NOX	Simple or Combined Cycle / DLN (Gas)	9.0 ppmvd @ 15% O_2, 3-hour/24-hour avg. 66.2 pounds per hour
	Simple or Combined Cycle / Wet Injection (Oil)	42.0 ppmvd @ 15% O_2, 3-hour avg. 362.4 pounds per hour
	Combined Cycle / SCR Option (Gas)	3.5 ppmvd @ 15% O_2, 3-hour avg. 25.8 pounds per hour
	Combined Cycle / SCR Option (Oil)	16.4 ppmvd @ 15% O_2, 3-hour avg. 141.3 pounds per hour
PM/PM10	All Modes / Clean Fuels and Combustion Design	Visible emissions - 10% opacity
SAM/SO2	All Modes / Natural Gas Specification	1 grain per 100 SCF of gas
	All Modes / Low Sulfur Distillate Oil Specification	0.04% sulfur by weight, 750 hours
VOC	All Modes / Combustion Design (Gas/Oil)	3.5/7.0 ppmvw as methane, 3-hour avg. 7.9/16.5 pounds per hour

Pollutant	Mode of Operation/Controls*	Emission Standard
EU-002: HRSG Duct Burner (Alone)		
NOx	Emissions Only From Duct Firing	0.08 lb/mmBTU of heat input, 3-hour avg.

* DLN means dry low-NOx controls. SCR means selective catalytic reduction with ammonia injection. Limits for combined cycle operation are the same whether the duct burner is fired or not.

6.2 BACT Compliance Demonstration

Following is a brief summary of the methods required to demonstrate compliance with the BACT limits specified above.

Pollutant	Compliance Methods*
CO	EPA Method 10: initial and annual tests concurrent with NOx.
NOx	EPA Method 20: initial and annual tests; continuous compliance shall be demonstrated with data from a certified continuous emissions monitor; annual RATA results may be substituted for annual tests if all capacity, notification, and reporting requirements are met.
PM/PM_{10}	EPA Method 9: initial and annual tests with visible emissions as a surrogate standard.
SO_2/SAM	Record keeping for the sulfur content of fuels delivered to the site.
VOC	Method 18, 25, or 25A: initial tests, thereafter compliance is assumed IF compliance with the CO and VE standards is maintained; test required during fiscal year prior to renewal.

* Compliance shall be demonstrated for each fuel type and each alternate mode of operation.

6.3 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:

Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the calculation of the 24-hour NOx averages for compliance determinations.

Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, or malfunction shall be allowed provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall not exceed two (2) hours in any 24-hour period except for the following modes of startup.

(a) *Cold Startup*: During a cold startup to combined cycle operation, up to four (4) hours of excess emissions are allowed in a 24-hour period. "Cold startup" is defined as startup to combined cycle operation following a steam turbine shutdown lasting 48 hours or more.

(b) *Warm Startup*: During a warm startup to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine shutdown lasting 8 hours or more, but less than 48 hours.

If excess emissions occur due to malfunction, the owner or operator shall notify the Compliance Authorities within one (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.

7.0 RECOMMENDATION AND APPROVAL

The permit project engineer and reviewing Professional Engineer is Jeff Koerner, P.E. The New Source Review Section recommends the above BACT determinations for this project. Additional details of this analysis may be obtained by contacting the project engineer, Jeff Koerner, at 850/414-7268 or the following address:

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

Recommended By:

(DRAFT)

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

Date: ______________

Approved By:

(DRAFT)

Howard L. Rhodes, Director
Division of Air Resources Management

Date: ______________

APPENDIX D - NSPS GENERAL PROVISIONS

NSPS General Provisions: Applicable portions of 40 CFR 60, Subpart A, General Provisions include:

- 40 CFR 60.7, Notification and Record Keeping
- 40 CFR 60.8, Performance Tests
- 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
- 40 CFR 60.12, Circumvention
- 40 CFR 60.13, Monitoring Requirements
- 40 CFR 60.19, General Notification and Reporting Requirements

For copies of these requirements, please contact the Department's New Source Review Section.

FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

SUBPART DB - INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

40 CFR 60.40B APPLICABILITY AND DELEGATION OF AUTHORITY.

(a) The affected facility to which this subpart applies is each steam generating unit that commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 million Btu/hour).

40 CFR 60.41B DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

Combined cycle system means a system in which a separate source, such as a gas turbine, internal combustion engine, kiln, etc., provides exhaust gas to a heat recovery steam generating unit.

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

Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc.

Heat transfer medium means any material that is used to transfer heat from one point to another point.

Maximum heat input capacity means the ability of a steam generating unit to combust a stated maximum amount of fuel on a steady state basis, as determined by the physical design and characteristics of the steam generating unit.

Natural gas means (1) a naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or (2) liquid petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835-82, ``Standard Specification for Liquid Petroleum Gases" (IBR--see Sec. 60.17).

Steam generating unit means a device that combusts any fuel or byproduct/waste to produce steam or to heat water or any other heat transfer medium. This term includes any municipal-type solid waste incinerator with a heat recovery steam generating unit or any steam generating unit that combusts fuel and is part of a cogeneration system or a combined cycle system. This term does not include process heaters as they are defined in this subpart.

40 CFR 60.42B STANDARD FOR SULFUR DIOXIDE.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for sulfur dioxide.}

40 CFR 60.43B STANDARD FOR PARTICULATE MATTER.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for particulate.}

40 CFR 60.44b STANDARD FOR NITROGEN OXIDES.

(a) On and after the date on which the initial performance test is completed or is required to be completed under Sec. 60.8 of this part, whichever date comes first, no owner or operator of an affected facility that is subject to the provisions of this section and that combusts only coal, oil, or natural gas shall cause to be discharged into the atmosphere from that affected facility any gases that contain nitrogen oxides (expressed as NO_2) in excess of the following emission limits:

Fuel/Steam generating unit type	Nitrogen Oxide Emission Limits (expressed as NO_2) (lb/million BTU of Heat Input)
(4) Duct burner used in a combined cycle system: (i) Natural gas and distillate oil	0.20

40 CFR 60.45b COMPLIANCE AND PERFORMANCE TEST METHODS AND PROCEDURES FOR SULFUR DIOXIDE.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for sulfur dioxide.}

40 CFR 60.46b COMPLIANCE AND PERFORMANCE TEST METHODS AND PROCEDURES FOR PARTICULATE MATTER AND NITROGEN OXIDES.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for particulate.}

(f) To determine compliance with the emission limit for nitrogen oxides required by Sec. 60.44b(a)(4) for duct burners used in combined cycle systems, the owner or operator of an affected facility shall conduct the performance test required under Sec. 60.8 using the nitrogen oxides and oxygen measurement procedures in 40 CFR part 60 appendix A, Method 20. During the performance test, one sampling site shall be located as close as practicable to the exhaust of the turbine, as provided by section 6.1.1 of Method 20. A second sampling site shall be located at the outlet to the steam generating unit. Measurements of nitrogen oxides and oxygen shall be taken at both sampling sites during the performance test. The nitrogen oxides emission rate from the combined cycle system shall be calculated by subtracting the nitrogen oxides emission rate measured at the sampling site at the outlet from the turbine from the nitrogen oxides emission rate measured at the sampling site at the outlet from the steam generating unit.

40 CFR 60.47b EMISSION MONITORING FOR SULFUR DIOXIDE.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for sulfur dioxide.}

40 CFR 60.48b EMISSION MONITORING FOR PARTICULATE MATTER AND NITROGEN OXIDES.

{Note: Because the duct burner fires only natural gas, it is not subject to a standard for particulate matter.}

(h) The owner or operator of an affected facility which is subject to the nitrogen oxides standards of Sec. 60.44b(a)(4) (duct burner) is not required to install or operate a continuous monitoring system to measure nitrogen oxides emissions. {Note: Continuous monitoring IS required by the BACT determination.}

40 CFR 60.49B REPORTING AND RECORDKEEPING REQUIREMENTS.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by Sec. 60.7. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility,

(3) The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

(b) The owner or operator of each affected facility subject to the sulfur dioxide, particulate matter, and/or nitrogen oxides emission limits under Secs. 60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B.

FEDERAL NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60, SUBPART GG - STATIONARY GAS TURBINES

This emissions unit is subject to 40 CFGR 60, Subpart GG for stationary gas turbines adopted by reference in Rule 62-204.800(7)(b), F.A.C. The following conditions follow the original NSPS rule language and numbering scheme. Regulations that are not applicable were omitted for clarity. Because this emissions units is subject to an NSPS, it is also subject to the following federal provisions: 40 CFR 60, Subpart A, General Provisions for sources subject to an NSPS, adopted by reference in Rule 62-204.800(7)(d), F.A.C.; 40 CFR 60, Appendix A - Test Methods, Appendix B - Performance Specifications, Appendix C - Determination of Emission Rate Change, Appendix D - Required Emissions Inventory Information, Appendix F - Quality Assurance Procedures, adopted by reference in Rule 62-204.800(7)(e).

40 CFR 60.330 APPLICABILITY AND DESIGNATION OF AFFECTED FACILITY.

(a) The provisions of this subpart are applicable to all stationary gas turbines with a heat input at peak load equal to or greater than 10 million BTU per hour, based on the lower heating value of the fuel fired.

40 CFR 60.331 DEFINITIONS.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

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

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

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

(f) Ice fog means an atmospheric suspension of highly reflective ice crystals.

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

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

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

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

(p) Gas turbine model means a group of gas turbines having the same nominal air flow, combustor inlet pressure, combustor inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

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

60.332 STANDARD FOR NITROGEN OXIDES.

(a) On and after the date of the performance test required by Sec. 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b) of this section shall comply with one of the following, except as provided in paragraphs (e) of this section.

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

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

Where:

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

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

F = NO emission allowance for fuel-bound nitrogen as defined in the following table:

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

Fuel-Bound Nitrogen (Percent By Weight)	"F" (NOx Percent By Volume)
N < 0.015	0
0.015 < N < 0.1	0.04(N)
0.1 < N < 0.25	0.004 + 0.0067(N – 0.1)
N > 0.25	0.005

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

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

(f) Stationary gas turbines using water or steam injection for control of NOx emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

40 CFR 60.333 STANDARD FOR SULFUR DIOXIDE.

On and after the date on which the performance test required to be conducted by Sec. 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

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

APPENDIX F - NSPS SUBPART GG (COMBUSTION TURBINE)

40 CFR 60.334 MONITORING OF OPERATIONS.

(a) The owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within +/- 5.0 percent and shall be approved by the Administrator.

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

(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.

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

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

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

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

(3) Ice fog. Each period during which an exemption provided in Sec. 60.332(g) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

40 CFR 60.335 TEST METHODS AND PROCEDURES.

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

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

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

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\,(P_r/P_o)^{0.5}\,(e^{19(Ho - 0.00633)})\,(288°K/T_a)^{1.53}$$

Where

NOx = emission rate of NOx at 15 percent oxygen and ISO standard ambient conditions, volume percent.

NOxo = observed NO<INF>x</INF> concentration, ppm by volume.

P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

P_o = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H<INF>2</INF>O/g air.

E = transcendental constant, 2.718.

T_a = ambient temperature, °K.

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

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

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

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

SECTION IV.

APPENDIX G - EXCESS EMISSION / MONITORING SYSTEM PERFORMANCE SUMMARY

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

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

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

Reporting period dates: From ________________ to ________________

Company: ________________________________

Emission Limitation: ________________________________

Address: ________________________________

Monitor Manufacturer and Model No.: ________________________________

Date of Latest CMS Certification or Audit: ________________

Process Unit(s) Description: ________________________________

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

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

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

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

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

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

Name: ________________________________

Signature: ________________________________

Title: ________________________________

Date: ________________

TECHNICAL EVALUATION

AND

PRELIMINARY DETERMINATION

LAKE WORTH GENERATION, LLC

260 Megawatt Combined Cycle Unit
Lake Worth, Palm Beach County, Florida

Facility I.D. No. 099-0568

Air Permit No. 099-0568-001-AC
PSD-FL-266

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

July 9, 1999

1. APPLICATION INFORMATION

1.1 Applicant Name and Address

Lake Worth Generation, L.L.C.
245 Winter Street, Suite 300
Waltham, MA 02451

Authorized Representative:
Brian Chatlosh, Manager

1.2 Reviewing and Process Schedule

03/15/99:	Date of Receipt of Application
04/09/99:	Preliminary DEP/BAR Incompleteness Letter
04/19/99:	Forwarded questions from NPS (received 04/16/99)
04/22/99:	DEP performed site inspection
05/04/99:	Department received additional information and request to modify application.
05-24-99:	Department received additional information regarding modification
06/08/99:	Department met with applicant's engineer
06/21/99:	Department received comments from NPS regarding BACT determination; forwarded to applicant's engineer
07/07/99:	Department received applicant's response to NPS comments regarding BACT
07-09-99:	Department mailed Intent to Issue PSD Permit

2. FACILITY INFORMATION

2.1 Facility Location

The new electrical generating power plant will be collocated with the existing Tom G. Smith Power Plant owned and operated by the City of Lake Worth at 117 College Street in Lake Worth, Florida 33461. This site is approximately 104 km north of the Everglades National Park, a Class I PSD Area. The UTM Coordinates are Zone 17, 592.8 km E, 43.7 km N.

2.2 Standard Industrial Classification Codes (SIC)

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

2.3 Facility Category

This project will create a new electrical generating power plant that will be collocated with the existing Tom G. Smith Power Plant, which is owned and operated by the City of Lake Worth. During combined cycle operation of the new combustion turbine, steam may be delivered to the existing steam turbines at the Tom G. Smith Power Plant to produce up to 74 MW of power.

This facility is classified as a "major" or Title V Source of air pollution because emissions of nitrogen oxides (NOX) and carbon monoxide (CO) exceed 100 tons per year.

This facility is not included in the 28 Major Facility Categories listed in Table 62-212.400-1, F.A.C. However, because nitrogen oxide emissions are greater than 250 tons per year, the facility is also "major" with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). As a PSD major facility, other pollutant emissions from this project greater than the Significant Emission Rates given in Table 212.400-2 will also require a PSD review and a determination of Best Available Control Technology (BACT). The following table summarizes the PSD applicability for this project.

Table 2.3-1: Emissions Summary and PSD Applicability

Pollutant	Emissions Rate In Tons Per Year			(M)ajor or (S)ignifcant	Subject To BACT?
	Project Potential Emissions[a,b]	Major Emissions Threshold	Significant Emissions Rate		
CO	204 (201)	NA	100	S	Y
NOx	438 (401)	250	40	M	Y
PM / PM_{10}	43 (42)	NA	25 / 15	S	Y
SAM	11 (8)	NA	7	S	Y
SO2	70 (50)	NA	40	S	Y
VOC	39 (38)	NA	40	N	N

Table Notes:

[a] - Original application based on 7760 hours of gas firing with 1000 hours of oil firing.

[b] - The final potential emissions are given in parentheses and are based on the draft permit limiting oil firing to 750 hours per year and 0.04% sulfur by weight.

This facility is not a major source of hazardous air pollutants (HAPs).

This facility is subject to the provisions of Title IV, the Acid Rain requirements of the Clean Air Act as amended in 1990.

Emissions units included in this project are subject to regulation under the New Source Performance Standards, 40 CFR 60, Subpart GG (Standards of Performance for Stationary Gas Turbines) and Subpart Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units).

Also, emissions units included in this project are subject to regulation under Rule 62-212.400, F.A.C. for a determination of the Best Available Control Technology (BACT).

3. PROJECT DESCRIPTION

This permit addresses the following emissions units:

ARMS ID No.	Emissions Unit Description
001	The **combustion turbine** is a General Electric Model Frame 7FA primarily fired with natural gas. It has a direct electrical generating capacity of 186 MW in simple cycle.
002	The **heat recovery steam generator** (HRSG) converts waste heat from the combustion turbine into steam during the combined cycle mode to produce an additional 74 MW of electricity from existing steam turbines. Supplemental low-NOx duct burners may be fired with natural gas to provide an additional maximum heat input of 175 mmBTU per hour.

The applicant, Lake Worth Generation, L.L.C. (LWG), proposes to install and operate a new combustion gas turbine to be located at 117 College Street in Lake Worth, Palm Beach County, Florida. LWG will enter into a long-term lease of this property from the City of Lake Worth that also operates the Tom G. Smith Power Plant located on the same site. Employees of the existing power plant will be used to operate and maintain the new combustion gas turbine. The combustion turbine will operate a significant amount of time in the simple cycle mode. When requested by the Tom G. Smith Power Plant, the combustion turbine will enter a combined cycle mode. The power plant will purchase this steam as a high priority when it is available and when there is a sufficient demand. Although collocated with the existing Tom G. Smith Power Plant, the applicant maintains that there is independent ownership and control of the new combustion turbine generating facility.

The new combustion gas turbine with electrical generator specified in the application is a General Electric Frame 7FA, Model No. PG7241(FA)CT. An absorption chiller system will pre-cool the inlet air to the combustion turbine to a nominal 55°F to increase the mass of the compressor inlet air and resulting power output. The GE Frame 7FA incorporates dry, low NOx (DLN) technology to reduce nitrogen oxides while maintaining low levels of carbon monoxide. This technology involves the premixing of natural gas with combustion air to provide a lean mix with staged combustion. Natural gas and low sulfur distillate oil storage is currently available at this site. The project also includes a heat recovery steam generator with duct firing.

In simple cycle mode, the combustion turbine produces only direct electrical power. The new unit will generate a maximum of 176 MW of power in simple cycle mode when burning natural gas as the primary fuel. For periods of natural gas curtailment, the combustion turbine will fire low sulfur distillate oil (up to 750 hours) to generate a maximum of 186 MW of power in simple cycle mode. The hot combustion gases exhaust at a temperature of approximately 1100°F through a bypass stack which is 22 feet in diameter and 98 feet high.

In combined cycle mode, the combustion turbine not only generates direct electrical power, but also produces steam-generated power by reclaiming useful energy from the hot combustion gases in a heat recovery steam generator (HRSG). The HRSG transfers the waste heat to boiler tubes and generates steam for sale to the collocated Tom G. Smith Power Plant. If necessary, a 200 mmBTU per hour duct burner may be fired with natural gas to improve the steam generating capacity. The steam is delivered to the Tom G. Smith Power Plant and used drive existing steam turbines with electrical generators to produce up to an additional 74 MW of power. Because the equipment will produce less than 75 MW of steam-generated power, this project is not subject to the power plant siting requirements. The cooled combustion gases exhaust at a temperature of approximately 220°F through the HRSG stack which is 18 feet in diameter and 150 feet high.

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. 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 General Electric Frame 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°F and generate a considerable amount of nitrogen oxides (NOx). Because of these very high temperatures, the regulation of combustion turbines has been focused on NOx reduction. Units such as the 7FA operate at lower flame temperatures that minimize NOx 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.

For this project, the unit will operate primarily in combined cycle mode, meaning that the combustion turbine directly drives an electric generator and waste heat from the exhaust gases is reclaimed in the heat recovery steam generator (HRSG). Steam will be delivered to the collocated Tom G. Smith power Plant to drive existing steam turbines that also drive electrical generators. Combustion turbines operating in combined cycle modes offer efficiencies over 55%.

Midway through this project, the applicant requested a modification to the application to include two alternate modes of operation: steam injection to the combustion turbine for power augmentation and supplemental duct firing in the HRSG. Steam injected into the combustion turbine increases the mass flow rate of air resulting in a boost in power production (power augmentation). The additional duct burner (175 mmBTU per hour) would be fired to ensure adequate steam for operating the absorption chiller and steam injection for power augmentation during the hottest days.

The project is also capable of operation in simple cycle mode providing only direct power generation. LWG expects to operate the unit in simple cycle mode during periods when the HRSG is not operational or when there is no demand for steam from the City of Lake Worth. Combustion turbines operating in combined cycle modes offer efficiencies of approximately 55%.

At high ambient temperature, the units cannot generate as much power because of lower compressor inlet density. To compensate for the loss of output (which can be on the order of 20 MW compared to referenced temperatures), an absorption chiller may be installed ahead of the combustion turbine inlet. The absorption chillers are designed for a minimum temperature of 45°F and a nominal temperature of 55°F.

The project includes highly automated controls, described as the SPEEDTRONIC™ Gas Turbine Control System. This system is designed to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: fuel distribution and staging, turbine speed, load conditions, combustion temperatures, water injection, and fully automated startup, shutdown, and cool-down.

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

5. RULE APPLICABILITY

The proposed project is subject to preconstruction review requirements under the provisions of 40 CFR 52.21, Chapter 403, Florida Statutes, and Chapters 62-4, 62-204, 62-210, 62-212, 62-214, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.).

This facility is located in Palm Beach 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), because the potential emission increases exceed the significant emission rates given in Chapter 62-212, Table 62-212.400-2, F.A.C.

This PSD review consists of a determination of Best Available Control Technology (BACT) for CO, NO_X, PM/PM_{10}, SAM/SO_2. An analysis of the air quality impacts from the proposed project upon soils, vegetation and visibility is required along with air quality impacts resulting from associated commercial, residential, and industrial growth. This project is not subject to Power

Plant Siting, Chapter 62-16, F.A.C., because less than 74 MW of steam-generated power will be produced.

The emission units affected by this PSD 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 62-204.260	Prevention of Significant Deterioration Increments
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 62-212.400	Prevention of Significant Deterioration
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 Db and GG
40 CFR 60	NSPS Subpart A, General Provisions
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. SOURCE IMPACT ANALYSIS

6.1 Emission Limitations

The proposed project will emit the following PSD pollutants (Table 212.400-2): particulate matter, sulfuric acid mist, sulfur dioxide, nitrogen oxides, volatile organic compounds, carbon monoxide, and negligible quantities of mercury and lead. The applicant's proposed annual emissions are summarized in the table below and form the basis of the source impact review. The proposed permitted allowable emissions are summarized in the Department's Draft Permit and BACT Determination.

6.2 Emission Summary

Potential project emissions were previously presented in Table 2.3-1 of this report. The ambient air quality analysis was based on the applicant's proposed potential emissions. The Draft Permit restricts low sulfur distillate oil firing to only 750 hours per year and reduces final potential emissions.

6.3 Control Technology

Emissions control will be primarily accomplished by good combustion of clean natural gas. The proposed General Electric Frame 7FA combustion turbine incorporates dry low-NOx (DLN) combustion technology that operates in lean pre-mixed mode to minimize the flame temperature and nitrogen oxides formation potential. Under normal operating conditions, DLN technology with this combustion turbine model has demonstrated emission levels below 9 ppmvd corrected to 15% oxygen for NOx and 12 ppmvd corrected to 15% oxygen for CO. Low NO_X burners will be utilized in the HRSG to achieve NOx levels below 0.08 pounds per mmBTU of heat input. The applicant is considering steam injection for power augmentation and a HRSG duct burner to periodically boost generating capacity. Because both of these options tend to defeat the control capabilities of DLN and may result in higher emissions, the Draft Permit includes the following optional control equipment: Selective catalytic reduction (SCR) with aqueous ammonia to further control NOx; and an oxidation catalyst for CO control. A full discussion is given in the Best Available Control Technology (BACT) Determination included in the Draft Permit. The Draft BACT is incorporated into this evaluation by reference.

6.4 Air Quality Analysis

6.4.1 Introduction

The proposed project will increase emissions of five pollutants at levels in excess of PSD significant amounts: PM_{10}, CO, NOx, SO_2, and H_2SO_4 mist. PM_{10}, SO_2, and NO_X are criteria pollutants and have national and state ambient air quality standards (AAQS), PSD increments, and significant impact levels defined for them. CO is a criteria pollutant and has only AAQS and significant impact levels defined for it. There are no applicable PSD increments or AAQS for H_2SO_4 mist.

The applicant's initial PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project predicted no significant impacts; therefore, further applicable AAQS and PSD increment impact analyses for these pollutants were not required. Based on the preceding discussion, the air quality analyses required by the PSD regulations for this project are the following:

- A significant impact analysis for PM_{10}, CO, SO_2, and NO_X; and
- An analysis of impacts on soils, vegetation, 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.

6.4.2 Models and Meteorological Data Used in the Significant Impact Analysis

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

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

For determining the project's significant impact area in the vicinity of the facility and if there are significant impacts from the project on any PSD Class I area, the highest predicted short-term concentrations and highest predicted annual averages were compared to their respective significant impact levels.

6.4.3 Significant Impact Analysis

Initially, the applicant conducts modeling using only the proposed project's emissions at worst load conditions. In order to determine worst-case load conditions the ISCST3 model was used to evaluate dispersion of emissions from the combined cycle facility for two loads (50% and 100%) and two seasonal operating conditions (summer and winter). If this modeling at worst-case load conditions shows significant impacts, additional multi-source modeling is required to determine the project's impacts on the existing air quality and any applicable AAQS and PSD increments. Receptors were placed 80 m from the facility, which is located in a PSD Class II area. They were also placed in the Everglades National Park (ENP), which is the closest PSD Class I Area. ENP is located approximately 104 km southwest of the project. The receptor grid for predicting maximum concentrations in the vicinity of the project was a polar receptor grid that contained 20 rings and 10° spacing radials with dimensions centered on the combined cycle facility stacks. The inner portion of the grid had rings at 20 m spacing out to 100 m. A 200 m spacing was used out to 1,100 m; a 400 m spacing was used out to 1,500 m; a 500 m spacing was used out to 3,000 m; a 1,000 m spacing was used out to 7,000 m; and a 3,000 m spacing was used out to 10,000 m. From 10,000 m to 30,000 m, a 5,000 m spacing was used. For predicting impacts at the ENP, 51 discrete receptors along the border of the PSD Class I area were used. For each PSD pollutant subject to PSD increment and/or AAQS analyses, this modeling analysis compares maximum predicted impacts due to the project with PSD significant impact levels to determine whether significant impacts due to the project are predicted in the vicinity of the facility or in the ENP. The tables below show the results of this modeling.

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS II SIGNIFICANT IMPACT LEVELS IN THE VICINITY OF THE FACILITY

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.04	1	NO
	24-hour	1.1	5	NO
CO	8-hour	7	500	NO
	1-hour	21	2000	NO
NO_2	Annual	0.49	1	NO
SO_2	Annual	0.16	1	NO
	24-hour	4.04	5	NO
	3-hour	12.01	25	NO

MAXIMUM PROJECT AIR QUALITY IMPACTS FOR COMPARISON TO THE PSD CLASS I SIGNIFICANT IMPACT LEVELS (CNWA)

Pollutant	Averaging Time	Max. Predicted Impact at Class I Area (ug/m^3)	Proposed EPA Significant Impact Level (ug/m^3)	Significant Impact?
PM_{10}	Annual	0.0008	0.2	NO
	24-hour	0.03	0.3	NO
NO_2	Annual	0.015	0.1	NO
SO_2	Annual	0.0043	0.1	NO
	24-hour	0.12	0.2	NO
	3-hour	0.57	1	NO

Initial modeling indicated a problem with the SO_2 Significant Impact Levels for Class II Areas. However, additional modeling based on a fuel sulfur limit of 0.04% sulfur by weight indicated no significant impacts. The results of the significant impact modeling show that there are no significant impacts predicted from emissions from this project; therefore, no further modeling was required.

6.4.4 Impacts Analysis

Impact Analysis for Soils, Vegetation, and Wildlife

Very low emissions are expected from this natural gas-fired combustion turbine in comparison with conventional power plant generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for PM_{10}, CO, NO_X, SO_2 and H_2SO_4 mist as a result of the proposed project, including background concentrations and all other nearby sources, will be less than the respective ambient air quality standards (AAQS). The project impacts are less than the significant impact levels that in-turn are less than the applicable allowable increments for each pollutant. Because the AAQS are designed to protect both the public health and welfare and the project impacts are less than significant, it is reasonable to assume the impacts on soils, vegetation, and wildlife will be minimal or insignificant.

Impact On Visibility

Natural gas and No. 2 distillate fuel oil are clean fuels and produce 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. A regional haze analysis was performed which shows that the proposed project will not result in adverse impacts on visibility in the nearest PSD Class I area.

Growth-Related Air Quality Impacts

There will be short-term increases in the labor force to construct the project. These temporary increases will not result in significant commercial and residential growth in the vicinity of the project. Operation of the additional unit will require minimal permanent employees that will cause no significant impact on the local area.

Over the past few years the Public Service Commission has determined that a number of power projects are needed to help meet the low electrical reserve capacity throughout the State of Florida. The project is a response to state-wide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the proposed project has a small overall physical "footprint," low water requirements, and the lowest air emissions currently achievable for this size unit inherent to the combustion turbine design.

7. CONCLUSION

Based on the foregoing technical evaluation of the application and additional information submitted by the applicant, the Department has made a preliminary determination that the proposed project will comply with all applicable state and federal air pollution regulations, provided the Department's BACT determination is implemented.

Jeff Koerner, P.E., Project Engineer
Chris Carlson, Project Meteorologist

Florida Department of Environmental Protection
2600 Blair Stone Road, MS #5505
Tallahassee, FL 32399-2400
850/488-0114

Florida Department of

Memorandum Environmental Protection

TO: Clair Fancy

FROM: Al Linero *[signature]* 7/8

DATE: July 9, 1999

SUBJECT: Lake Worth Generating, LLC
260 MW Combined Cycle Combustion Turbine Project (PSD-FL-266)

Attached is the public notice package for construction of a 186 MW General Electric Model PG7241FA gas-fired combustion turbine at a proposed new power generating facility. The applicant, Lake Worth Generation, L.L.C. (LWG), proposes to install and operate a new combustion gas turbine to be located at 117 College Street in Lake Worth, Palm Beach County, Florida. LWG will enter into a long-term lease of this property from the City of Lake Worth that also operates the Tom G. Smith Power Plant located on the same site. The combustion turbine will operate a significant amount of time in the simple cycle mode (186 MW, maximum). When requested by the Tom G. Smith Power Plant, the combustion turbine will enter a combined cycle mode (260 MW, maximum). The power plant will purchase this steam as a high priority when it is available and when there is a sufficient demand. Although collocated with the existing Tom G. Smith Power Plant, the applicant maintains that there is independent ownership and control of the new combustion turbine generating facility.

The new combustion gas turbine with electrical generator is a General Electric Frame 7FA, Model No. PG7241(FA). An absorption chiller system will pre-cool the inlet air to the combustion turbine to a nominal 55°F to increase the mass of the compressor inlet air and resulting power output. The GE Frame 7FA incorporates dry, low NOx (DLN) technology to reduce nitrogen oxides while maintaining low levels of carbon monoxide. This technology involves the premixing of natural gas with combustion air to provide a lean mix with staged combustion. Natural gas and low sulfur distillate oil storage is currently available at this site. The project also includes a heat recovery steam generator (HRSG) with duct firing.

Nitrogen Oxides (NO_X) emissions from the gas turbine will be controlled by dry low-NOx combustors capable of achieving emissions of 9 parts per million (ppm) by volume at 15 percent oxygen. Emissions of 42 ppm NOx will be achieved during the limited low sulfur distillate oil use (an equivalent of 750 hours per year). Emissions of carbon monoxide, volatile organic compounds, sulfur dioxide, sulfuric acid mist, and particulate matter (PM/PM10) 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.

Midway through the project, the applicant requested the addition of a HRSG duct burner (175 mmBTU per hour) and steam injection for power augmentation. During peak energy demands, the HRSG duct burner would ensure adequate steam to support the absorption chiller and steam injection for power augmentation. These modes of operation have the potential to increase CO and NOx emissions significantly above the originally proposed emission levels. It is the Department's position that both of these alternate-operating modes may defeat the arguments made for the emissions standards proposed as BACT for the DLN technology. We believe low-NOx technology for duct burners can maintain combined combustion turbine and duct burner emissions at 9 ppmvd with some power augmentation. Therefore, the BACT emissions standards remain the same for these modes of operation. Alternatively, the Draft Permit allows the applicant to install optional controls for CO (oxidation catalyst) and NOx (selective catalytic reduction.) to ensure compliance during these alternate modes of operation. If elected, the unit would be required to meet more stringent emissions standards.

Although there have been recent BACT NO_X determinations as low as 3.5 ppm in Region IV, we do not recommend such low values. Our recommended values equate to approximately 0.01 to 0.025 lb/mmBtu from a conventional coal-fired plant after correction for the higher thermal efficiency of the combined cycle. For example, the OUC Stanton II coal-fired plant achieves 0.17 lb/mmBtu with SCR.

I recommend your approval of the attached Intent to Issue.

AAL/jfk

Attachments

Department of Environmental Protection

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

Jeb Bush
Governor

David B. Struhs
Secretary

P.E. Certification Statement

Permittee:

Lake Worth Generating, LLC
Lake Worth, Palm Beach County, Florida

DEP File No. PSD-FL-266

Air Permit No. 0990568-001-AC

Project type:

Project will be at 117 College Street in Lake Worth, Palm Beach County, Florida. Project is construction of a 186 MW (maximum) GE PG7241FA, gas and oil-fired, combined cycle combustion turbine with a supplementary-fired heat recovery steam generator (HRSG) Steam will be sold to the collocated Tom G. Smith Power Plant owned and operated by the City of Lake Worth. Project includes separate stacks for combined cycle and simple cycle operation. Fuel oil firing (0.04% sulfur by weight) will be limited to 750 hours per year.

Baseload nitrogen oxides (NOx) limits are 9 ppmvd corrected to 15% oxygen for gas firing achievable by Dry Low NOx and 42 ppm for oil firing by water injection. Steam injection for power augmentation and ducts firing are permitted provided the DLN emission standards are met. Otherwise the applicant may choose to install optional control equipment and meet more stringent standards. Good combustion and use of clean fuels will control other pollutants, including PM/PM10, CO, VOC, SAM, and SO_2.

Impacts due to the proposed project emissions are all less than the applicable significant impact limits corresponding to the nearest PSD Class I Area (Everglades National Park) and Class II areas.

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

Jeffery J. Koerner 7-8-99

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

Department of Environmental Protection
Bureau of Air Regulation
New Source Review Section
111 South Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Phone (850) 414-7268
Fax (850) 922-6979