**Memorandum** Florida Department of Environmental Protection

TO: Michael Cooke, Director, Division of Air Resources Management

THROUGH: Trina Vielhauer, Chief, Bureau of Air Regulation
Al Linero, Administrator, New Source Review Section

FROM: Greg DeAngelo

DATE: August 22, 2003

SUBJECT: Florida Power Hines Energy Complex
Project No. 1050234-006-AC
PSD Permit No. 330
Power Block 3; New 530 MW "2-on-1" Combined Cycle Gas Turbine

The final permit is attached for your approval and signature to authorize the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The project is subject to power plant site certification.

On March 5, 2003, the Department distributed a draft permit package. The "Public Notice of Intent to Issue Permit" was published in the Lakeland Ledger on March 21, 2003. The Department received the proof of publication on March 28, 2003. On March 21, 2003, the applicant requested and received from the Department an order granting additional time in which to file a petition for an administrative hearing. On April 25, 2003, the applicant acknowledged the expiration of its Request for Enlargement of Time to file a petition for a formal administrative proceeding. There were no other requests for extensions or petitions filed on this project.

Changes to the draft permit are summarized in the attached Final Determination. The changes were not considered substantial. The draft certification document (including the revised PSD permit conditions) was presented at the site certification hearing held on August 12, 2003. The project received no adverse comments regarding air quality. The Governor and Cabinet approved the site certification.

I recommend your approval and signature.

Attachments

**STATE OF FLORIDA**
**DEPARTMENT OF ENVIRONMENTAL PROTECTION**

**NOTICE OF FINAL PERMIT**

In the Matter of an
Application for Permit by:

Progress Energy Florida
Hines Energy Complex
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Air Permit No. PSD-FL-330
Project No. 1050234-006-AC
Combined Cycle Power Block 3
Polk County, Florida

*Authorized Representative:*
Roger Zirkle, Plant Manager – Hines Energy Complex

Enclosed is the Final Permit Number PSD-FL-330. This permit authorizes construction of combined cycle Power Block 3 at the existing Hines Energy Complex power plant, which is located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade in Polk County, Florida. As noted in the Final Determination (attached), the Florida Department of Environmental Protection (DEP, or "the Department") made only minor changes to the Final Permit. This permit is issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within thirty (30) days from the date this order is filed with the Clerk of the Department.

In addition to the appeal process described above, Federal appeals procedures concerning this Prevention of Significant Deterioration (PSD) permit are outlined in 40 Code of Federal Regulations (CFR) 124.19. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within thirty (30) days of issuance of this order. Petitions may be addressed to the Environmental Appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C., 20460. Further details are available at http://www.epa.gov/eab.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

## CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 9/19/03 to the person(s) listed:

Mr. Roger Zirkle, Florida Power *
Mr. John J. Hunter, Florida Power *
Mr. Ken Kosky, Golder Associates Inc.
Mr. Jerry Kissel, SWD
Mr. Hamilton S. Oven, DEP-Siting
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

**FILING AND ACKNOWLEDGMENT FILED,** on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson September 19, 2003
(Clerk) (Date)

The Department distributed a public notice package on March 3, 2003 for the construction of Power Block 3 at the existing Progress Energy Florida's Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. The Public Notice of Intent to Issue was published in the Lakeland Ledger on March 21, 2003.

**COMMENTS/CHANGES**

The Department did not receive comments from the public, the National Park Service, nor the Department's Southwest District Office. The Department received comments from the U.S. Environmental Protection Agency (EPA) by letter dated April 17, 2003. The Department received comments from the applicant by letter dated April 8, 2003.

EPA and the applicant commented only on the draft permit and not on the Technical Evaluation and Preliminary Determination. The comments are summarized below and the Department's responses are included following each comment.

1. Prevention of Significant Deterioration (PSD) applicability. EPA noted that Power Block 2 is still under construction and that the issuance of the Power Block 2 construction permit (June 2001) and Progress Energy Florida's submittal of the Power Block 3 application (September 2002) are separated by only 15 months.. EPA recommended that the Department consider evaluating these two projects together with regards to PSD applicability.

   *Response*: EPA policy regarding avoiding PSD review by phasing in large construction projects through a series of smaller projects is clear. The Department agrees that such attempts to circumvent the PSD program are not allowed and prohibitions against such phasing should be stringently upheld.

   The Hines Energy Complex site has been certified by Florida's Public Service Commission to an ultimate site capacity of 3000 megawatts (MW). This capacity will be brought on line as population growth and electric demand increases, and capacity will naturally be developed in discrete phases. Power Block 3, for example, adds 530 MW to the site, bringing its total to 1560 MW. *The Department believes Power Block 3 to be a separate and distinct project from Power Block 2* while admitting that both projects are part of the larger goal of increasing the overall capacity of the site. (The Department also notes that the issuance of the Power Block 2 permit was somewhat delayed, and that the Power Block 2 *submittal* in July 2000 was 25 months prior to the Power Block 3 submittal.)

   While Power Block 3 is certainly the next "phase" in developing the site to its ultimate capacity, the Department stresses that the Power Block 3 application did not attempt to avoid PSD review through phasing. Power Block 2 and 3 both individually triggered and went through PSD review; both projects include Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), ozone/volatile organic compounds (VOC), particulate matter ($PM/PM_{10}$), and sulfuric acid mist (SAM). Emissions of other PSD pollutants regulated by Florida's program (fluorides, lead, and mercury) are negligible (two orders of magnitude below the threshold values triggering PSD review). Total reduced sulfur and reduced sulfur compounds are not anticipated to be emitted from the combustion turbines.

With regards to hazardous air pollutant (HAP) emissions, the facility is a major source of HAP but the project's estimated emissions for the maximum single HAP, formaldehyde (2.0 tons per year), and total HAP (7.25 tons per year) are below the thresholds requiring a case by case determination of Maximum Achievable Control Technology (MACT) pursuant to Section 112(g) of the Clean Air Act. Even doubled to take both Power Block 2 and Power Block 3 into account, these emission estimates are still below the 10 or 25 tons per year trigger for single or aggregate HAP, respectively. The Department also notes that the permit is clear regarding control of HAP emissions in the future through compliance with the to-be-promulgated National Emission Standards for Hazardous Air Pollutants (NESHAP) for Combustion Turbines (proposed 40 CFR 63, Subpart GG).

2. Name changes. The applicant requested that the corporation's name be updated from "Florida Power Corporation" to "Progress Energy Florida," and that the Authorized Representative reflect Roger Zirkle instead of Bruce Baldwin.

   *Response*: The requested changes update not only the company's changed name but also the current plant manager for the Hines Energy Complex. Since these changes do not reflect a change in ownership, no additional forms or information are needed to make this administrative correction. The final permit reflects the requested name changes.

3. Power Block 1. The applicant noted that a May 27, 1999, PSD modification at Power Block 1 updated that power block's nominal rating from 485 to 500 MW. The draft permit incorrectly lists the nominal rating for Power Block 1 at 485 MW.

   *Response*: The final permit reflects the 500 MW nominal rating for Power Block 1.

4. Oxidation catalyst. The permit requires that the heat recovery steam generators (HRSGs) be designed such that an oxidation catalyst for CO control can readily be installed; it also specifies the design criteria for the catalyst. The applicant asked that the target performance for the oxidation catalyst for oil firing be raised.

   *Response*: The final permit will maintain the ratio of CO limits for natural gas versus oil firing should the oxidation catalyst prove necessary, and it clarifies that the design shall be for "7.0 ppmvd corrected to 15% oxygen when distillate oil is fired ."

5. Ammonia emission limit. Citing the need to inject higher levels of ammonia during oil firing, the applicant requested a higher ammonia emission limit when firing distillate oil (9 ppmvd corrected to 15% oxygen) versus when firing natural gas (5 ppmvd corrected to 15% oxygen).

   *Response*: The Department believes that a 5 ppmvd ammonia "slip" while firing distillate oil is an attainable and appropriate design parameter; in addition, changing this emission limit is beyond the scope of making corrections without an additional public notice.

6. Continuous monitor span ranges. The applicant noted that the span values for the continuous emissions monitoring (CEM) systems should be set at a level insuring accurate data collection at all times, including elevated emissions during startups, shutdowns, and malfunctions.

   *Response*: The final permit requires dual span CEM systems for both CO and $NO_X$ emissions. In addition, the final permit specifies that the upper range "shall be set at a level that provides for accurate measurement during startups and shutdowns." The actual span value to use for the upper range will be submitted along with the CEM system verification protocol for approval by the Department.

The Department also determined that minor corrections or changes must be made to the draft permit text to clarify the original requirements. The corrections or changes are summarized below. All corrections and changes are referenced to Section III - Emissions Unit Specific Conditions of the permit.

<u>Condition No. 4:</u> Added language to clarify that the gas turbine $NO_X$ controls shall be tuned "in conjunction with any post-combustion emissions control equipment" to achieve the permitted levels for CO and $NO_X$ emissions. The combustion system does not have to be tuned to meet the emission standards independent of the post-combustion controls.

<u>Condition No. 9</u>: Clarified that the design of the selective catalytic reduction (SCR) system shall be based on an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen "when firing natural gas."

<u>Condition No. 13(d), 13(e), 20(g), and 26</u>: Clarifying edits were made to these conditions to eliminate duplicative and overlapping requirements. These conditions in the final permit contain no substantive changes to the requirements of the draft permit.

<u>Condition No. 20(a) and 20(b)</u>: Added "[except] as otherwise specified by this condition" to clarify that the upper range selected by the applicant and approved by the Department can vary from the upper range listed in the referenced performance specifications.

<u>Condition No. 20(a) and 20(b)</u>: Removed "as corrected to 15% oxygen" from the required span values for the lower ranges of the CO and $NO_X$ CEM systems. Span values are set considering actual stack concentrations, not corrected values.

## CONCLUSION

The final action of the Department is to issue the permit with the changes described above.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

**PERMITTEE:**

Progress Energy Florida
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

*Authorized Representative:*
Roger Zirkle, Plant Manager – Hines Energy Complex

Hines Energy Complex, Power Block 3
Project No. 1050234-006-AC
Air Permit No. PSD-FL-330
SIC No. 4911

Expires: June 30, 2007

## PROJECT AND LOCATION

This permit authorizes the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

## STATEMENT OF BASIS

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

## CONTENTS



Michael G. Cooke — 9/18/03

Michael Cooke, Director
Division of Air Resources Management

(Date)

## FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 3), the plant will have a total generating capacity of approximately 1,560 MW.

## NEW AND MODIFIED EMISSIONS UNITS

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

| ID | Emission Unit Description |
|---|---|
| 016 | Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG) |
| 017 | Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG) |

*{Permitting Note: The Hines Energy Complex, Power Block 3 (Power Block 3, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 3A and CT 3B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}*

## REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). Each Power Block 3 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary combustion turbine requirements of 40 CFR 63, Subpart YYYY, when that subpart is promulgated. (See Appendix YYYY.)

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

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

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

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

## PERMITTING AUTHORITY

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

**COMPLIANCE AUTHORITY**

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

**APPENDICES**

The following Appendices are attached as part of this permit.

| | |
|---|---|
| Appendix AL | Acronym List |
| Appendix BD | Final BACT Determinations and Emissions Standards |
| Appendix CF | Citation Format and Definitions |
| Appendix GC | General Conditions |
| Appendix GG | NSPS Subpart GG Requirements for Gas Turbines |
| Appendix SC | Standard Conditions |
| Appendix XS | Semiannual NSPS Excess Emissions Report |
| Appendix YYYY | NESHAP Subpart YYYY |

**REVIEWING AND PROCESSING SCHEDULE**

| | |
|---|---|
| September 4, 2002 | Received permit application and fee |
| November 7, 2002 | Department's request for additional information (via Office of Siting Coordination's sufficiency questions) |
| December 19, 2002 | Received response to sufficiency questions |
| February 19, 2003 | Received report documenting commercial, residential, and industrial growth since August 7, 1977 |
| February 19, 2003 | Application complete |
| March 5, 2003 | Distributed Notice of Intent to Issue and supporting documents |
| March 21, 2003 | Notice of Intent to Issue published in the *Lakeland Ledger* |

**RELEVANT DOCUMENTS**

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

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Technical Evaluation and Best Available Control Technology (BACT) Determination
- Department's Intent to Issue

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

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

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

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

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

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

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

This section of the permit addresses the following emissions units.

**Emission Units 016 and 017**

**Description**: Emission units 016 and 017 each consist of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

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

**Generating Capacity**: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

**Controls**: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/$PM_{10}$, SAM, $SO_2$ and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

**Stack Parameters**: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

| Fuel | Heat Input Rate (HHV) | Compressor Inlet Temp | Exhaust Temperature | Exit Velocity | Flow Rate |
|---|---|---|---|---|---|
| Gas | 1,830 MMBtu/hour | 59 °F | 190 °F | 59.2 ft/sec | 1,009,487 acfm |
| Oil | 1,932 MMBtu/hour | 59 °F | 270 °F | 67.0 ft/sec | 1,139,394 acfm |

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

## APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, PM/$PM_{10}$, sulfuric acid mist (SAM), $SO_2$, and VOC. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

## EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of

170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

6. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen when natural gas is fired and 7.0 ppmvd corrected to 15% oxygen when distillate oil is fired. [Rule 62-4.070(3), F.A.C.]

**PERFORMANCE RESTRICTIONS**

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

   c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

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

**EMISSIONS STANDARDS**

9. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | 5 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| $PM/PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| $SAM/SO_2$ [f] | Fuel specifications. |

   a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to Condition No. 6 of this section.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

f. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}* [Rule 62-212.400(BACT), F.A.C.]

**STARTUP, SHUTDOWN, AND MALFUNCTION EMISSIONS**

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

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

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

13. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section.

    a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period.

    b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block.

    c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

    d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in Condition No. 26 of this section.

    e. All periods of data excluded for any startup, shutdown, oil-to-gas fuel switch, or documented malfunction shall be consecutive for each episode. Periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed six hours in any 24-hour block period during which a cold startup occurred. For all other 24-hour block periods, periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed four hours.

    f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction.

    [Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

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

**EMISSIONS PERFORMANCE TESTING**

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

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | *Procedure for Collection and Analysis of Ammonia in Stationary Sources*<br>This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. |
| 7E | *Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)* |
| 9 | *Visual Determination of the Opacity of Emissions from Stationary Sources*<br>The test shall be conducted for a minimum of 30 minutes. |
| 10 | *Determination of Carbon Monoxide Emissions from Stationary Sources*<br>This method shall be based on a continuous sampling train. |
| 18 | *Measurement of Gaseous Organic Compound Emissions by Gas Chromatography*<br>(Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. |
| 20 | *Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines* |
| 25A | *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer* |

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

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

17. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of PM/$PM_{10}$ and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

    a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

*{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

19. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

### CONTINUOUS MONITORING REQUIREMENTS

20. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

a. *CO Monitors.* Except as otherwise specified by this condition, the CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

b. *NOx Monitors.* Except as otherwise specified by this condition, the NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

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

d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures $CO_2$ on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

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

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section.

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

*{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}* [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

21. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

**RECORDS AND REPORTS**

23. Monitoring of Operation: To demonstrate compliance with the fuel consumption limits of Condition No. 8 of this section, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

24. Frequency of Recordkeeping: Condition No. 20 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

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

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

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

26. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition No. 13 of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

28. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 13 and 14 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

## CONTENTS

## ACRONYM LIST

| | |
|---|---|
| acfm | Actual cubic feet per minute |
| ASTM | ASTM International [1] |
| BACT | Best Available Control Technology |
| Btu | British thermal unit |
| CAA, or "the ACT" | Clean Air Act, as amended in 1990 |
| CEMS | Continuous emission monitoring system |
| CFR | Code of Federal Regulations |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| DLN | Dry-low NOx |
| EPA | U.S. Environmental Protection Agency |
| F.A.C. | Florida Administrative Code |
| F.S. | Florida Statutes |
| FDEP, or "the Department" | Florida Department of Environmental Protection |
| HAP | Hazardous air pollutant |
| HHV | Higher heating value |
| HRSG | Heat recovery steam generator |
| LAER | Lowest Achievable Emission Rate |
| LHV | Lower heating value |
| MMBtu | Million British thermal units |
| MW | megawatt |
| NAAQS | National Ambient Air Quality Standards |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOx | Nitrogen oxides |
| NSPS | New Source Performance Standards |
| $PM/PM_{10}$ | Particulate matter |
| PSD | Prevention of Significant Deterioration |
| RACT | Reasonably Available Control Technology |
| RATA | Relative accuracy test assessment |
| SCR | Selective catalytic reduction |
| SNCR | Selective non-catalytic reduction |
| $SO_2$ | Sulfur dioxide |
| VOC | Volatile organic compound |

[1] Formerly known as American Society for Testing and Materials.

## FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

### OVERVIEW

The project added a 530 megawatt (MW) "2-on-1" combined cycle gas turbine system to the existing Florida Power Hines Energy Complex. Significant emissions increases pursuant to the Prevention of Significant Deterioration (PSD) rule required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter ($PM/PM_{10}$), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$), and volatile organic compounds (VOC).

### BACT CONTROL TECHNOLOGIES

The Florida Department of Environmental Protection (the "Department") reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" as revised prior to the siting hearing. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

<u>BACT for CO Emissions</u>

*Good Combustion and Operating Practices*: BACT for CO emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. Siemens Westinghouse's dual-fuel combustors have demonstrated very low CO emissions while simultaneously reducing NOx emissions for gas and oil firing.

*Catalytic Oxidation*: At the anticipated CO emissions rate, the Department does not consider the addition of a catalytic oxidation system for control of CO to be cost-effective. Catalytic oxidation – while not BACT – must be considered in the design of the heat recovery steam generators. The design must be such that the oxidation catalyst system can be readily installed in the future. If the as-built combined cycle unit cannot achieve the BACT CO emission limit, however, then the cost-effectiveness of the catalytic oxidation system improves and the Department shall require it to be installed.

<u>BACT for NOx Emissions</u>

*Dry Low-NOx (DLN) Combustion*: When firing natural gas, BACT for NOx emissions is the operation of Siemens Westinghouse's DLN combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in low NOx emissions. The control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

*Wet Injection*: When firing distillate oil, BACT for NOx emissions is the operation of Siemens Westinghouse's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

*Selective Catalytic Reduction (SCR)*: When firing natural gas or distillate oil, BACT for NOx emissions is the operation of the SCR system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the heat recovery steam generator, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. The SCR system will achieve about a 70% reduction with an initial ammonia slip of no more than 5 ppmvd.

<u>BACT for VOC Emissions</u>

*Good Combustion and Operating Practices*: BACT for VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. Siemens Westinghouse's dual-fuel combustors have demonstrated very low VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

BACT for PM, SAM, and SO2 Emissions

*Fuel Specifications*: BACT for PM, SAM, and SO2 emissions is the use of natural gas as the primary fuel ($\leq$ 1.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil ($\leq$ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

**BACT STANDARDS**

The following summarizes the final BACT determinations for this project in accordance with Rule 62-212.400 (BACT), F.A.C.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | 5 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| PM/$PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| SAM/$SO_2$ [f] | Fuel specifications. |

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of Section III of this permit, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

e. The fuel specifications established in Condition No. 8 of Section III of this permit – combined with the efficient combustion design and operation of each gas turbine – represents the BACT determination for PM/$PM_{10}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. 8 of Section III of this permit effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of Section III of this permit.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}*

If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall: begin testing and reporting the ammonia slip for each subsequent calendar quarter; before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions. Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

**FINAL BACT DETERMINATIONS**

As summarized above, the Department determines that the standards specified in this permit represent BACT for emissions of CO, NOx, PM/$PM_{10}$, SAM, $SO_2$, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

**DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:**

Gregory P. DeAngelo, P.E. Review Engineer, New Source Review Section
A. A. Linero, P.E. Administrator, New Source Review Section
Deborah Nelson, Meteorologist, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

| *Recommended By:* | *Approved By:* |
| --- | --- |
| Trina L Vielhauer | Michael G. Cooke |
| Trina Vielhauer, Chief<br>Bureau of Air Regulation | Michael Cooke, Director<br>Division of Air Resources Management |

## CITATION FORMAT AND DEFINITIONS

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

### REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

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

PSD Permit Numbers

*Example*: Permit No. PSD-FL-330

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

### RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

*Example*: [40 CFR 60.7]

*Means*: Title 40, Part 60, Section 7 of the Code of Federal Regulations

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

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

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

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

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

## GENERAL CONDITIONS

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

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);

    b. Determination of Prevention of Significant Deterioration (X); and

    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;

        2) The person responsible for performing the sampling or measurements;

        3) The dates analyses were performed;

        4) The person responsible for performing the analyses;

        5) The analytical techniques or methods used; and

        6) The results of such analyses.

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

Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR Part 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

**§ 60.331 Definitions.**

The following applicable terms are defined by this subpart:

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

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

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

(g) ISO standard day conditions 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.

(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 § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

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

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

(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) |
|---|---|
| $N \leq 0.015$ ........................................ | 0 |
| $0.015 < N \leq 0.1$ ............................... | 0.04(N) |
| $0.1 < N \leq 0.25$ ................................. | 0.004+0.0067(N−0.1) |
| $N > 0.25$ .......................................... | 0.005 |

where:

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

Department requirement: **While firing gas, the "F" value shall be assumed to be 0.**

**[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]**

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

**§ 60.333 Standard for Sulfur Dioxide.**

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

(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.

**[Note: The BACT limits of this permit are more stringent than this requirement.]**

**§ 60.334 Monitoring of Operations.**

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

(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.

Department requirement: **The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.**

**[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]**

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

**Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.**

**[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]**

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

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

**Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in Condition No. 27 of Section III of this permit.**

**Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by Condition No. 28 of Section III of this permit shall be used to demonstrate compliance with this requirement.**

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

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

### § 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 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

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

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

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

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

where:

NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

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

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

Ho = observed humidity of ambient air, g H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

**Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.**

**[Note: This is consistent with guidance from EPA Region 4.]**

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

**Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.**

**[Note: This is consistent with guidance from EPA Region 4.]**

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

**Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance be based on a**

**minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in Condition No. 20 of Section III of this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.**

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

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

**Department requirement: Condition No. 25 of Section III of this permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.**

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

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

**[Note: The fuel analysis requirements of Condition No. 25 of Section III of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]**

## STANDARD CONDITIONS

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

### EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

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

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

### TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

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

**RECORDS AND REPORTS**

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

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

## SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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

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

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

Reporting period dates: From ______________________ to ______________________

Company: ______________________

Emission Limitation: ______________________

Address: ______________________

Monitor Manufacturer: ______________________

Model No. : ______________________

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ______________________

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

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

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

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

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

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

*Name*: ______________________

*Signature*: ______________________ *Date*: ______________________

*Title*: ______________________

## NESHAP SUBPART YYYY

### APPLICABILITY

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new stationary **combustion turbine** requirements of 40 CFR 63, Subpart YYYY, when that subpart is finalized.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

### TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003, and it was signed by the Administrator on August 27, 2003.

The permittee shall apply for a permit revision to this permit to incorporate the relevant requirements of 40 CFR 63, Subparts A and YYYY, and ensure compliance with those standards prior to startup of the Power Block 3 combustion turbines.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. John J. Hunter
Project Technical Specialist
Progress Energy Florida, Inc.
Post Office Box 14042, MAC-BB1A
St. Petersburg, FL 33733-4042

***COMPLETE THIS SECTION ON DELIVERY***

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

C. Signature
X ☐ Agent ☐ Addressee

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

ST. PETERSBURG CALLER SERVICE
SEP 22 2003

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

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

2. 7001 0320 0001 3692 6082

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

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

7001 0320 0001 3692 6082

OFFICIAL USE

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

Postmark Here

*Sent To* John J. Hunter
*Street, Apt. No.; or PO Box No.* PO Box 14042, MAC-BB1A
*City, State, ZIP+4* St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Roger Zirkle
Plant Manager - Hines Energy Complex
Progress Energy Florida
Post OFfice Box 14042-MAC-BB1A
St. Petersburg, FL 33733-4042

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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

ST. PETERSBURG, FL 33733
SEP 22 2003
CARRIER SERVICE

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

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

2. 7001 0320 0001 3692 6075

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

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

7001 0320 0001 3692 6075

OFFICIAL USE

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

Postmark Here

*Sent To*
Roger Zirkle
*Street, Apt. No.; or PO Box No.*
PO Box 14042, MAC -BB1A
*City, State, ZIP+4*
St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

## Vielhauer, Trina

**From:** Hunter, John J (Jamie) [John.Hunter@pgnmail.com]
**Sent:** Tuesday, October 12, 2004 3:25 PM
**To:** ROBERT A MANNING; Halpin, Mike; Comer, Patricia
**Cc:** Vielhauer, Trina
**Subject:** Hines Power Block 3 - Construction Contract

As discussed, please find below additional information regard the construction contract for the Hines Power Block 3 project.

The following information briefly summarizes Contract No. 148701 - "General Terms and Conditions for the Design and Construction Contract for Hines Power Block 3".

- The scope of the contract requires the contractor to perform or manage all aspects of the engineering, procurement, and construction (including management and engineering staff, labor, tools, equipment, materials, parts, transportation, and supervision) for the balance of plant installation of a combined cycle power plant, with the equipment supplied by the owner, including two SWPC 501FD combustion turbine generators, two heat recovery steam generators, a single steam turbine generator, three generator step-up transformers, one surface condenser, and two auxiliary transformers at the Hines PB3 jobsite.
- The effective date of the contract is September 22, 2003.
- The contract is between PROGRESS ENERGY FLORIDA, Inc. and S&B/Bibb Hines PB3 Joint Venture, a joint venture consisting of S&B Engineers and Constructors Ltd. and Bibb and Associates, Inc.
- The S&B/Bibb office is located at 3535 Sage Road, 2nd Floor, Houston, TX 77056.

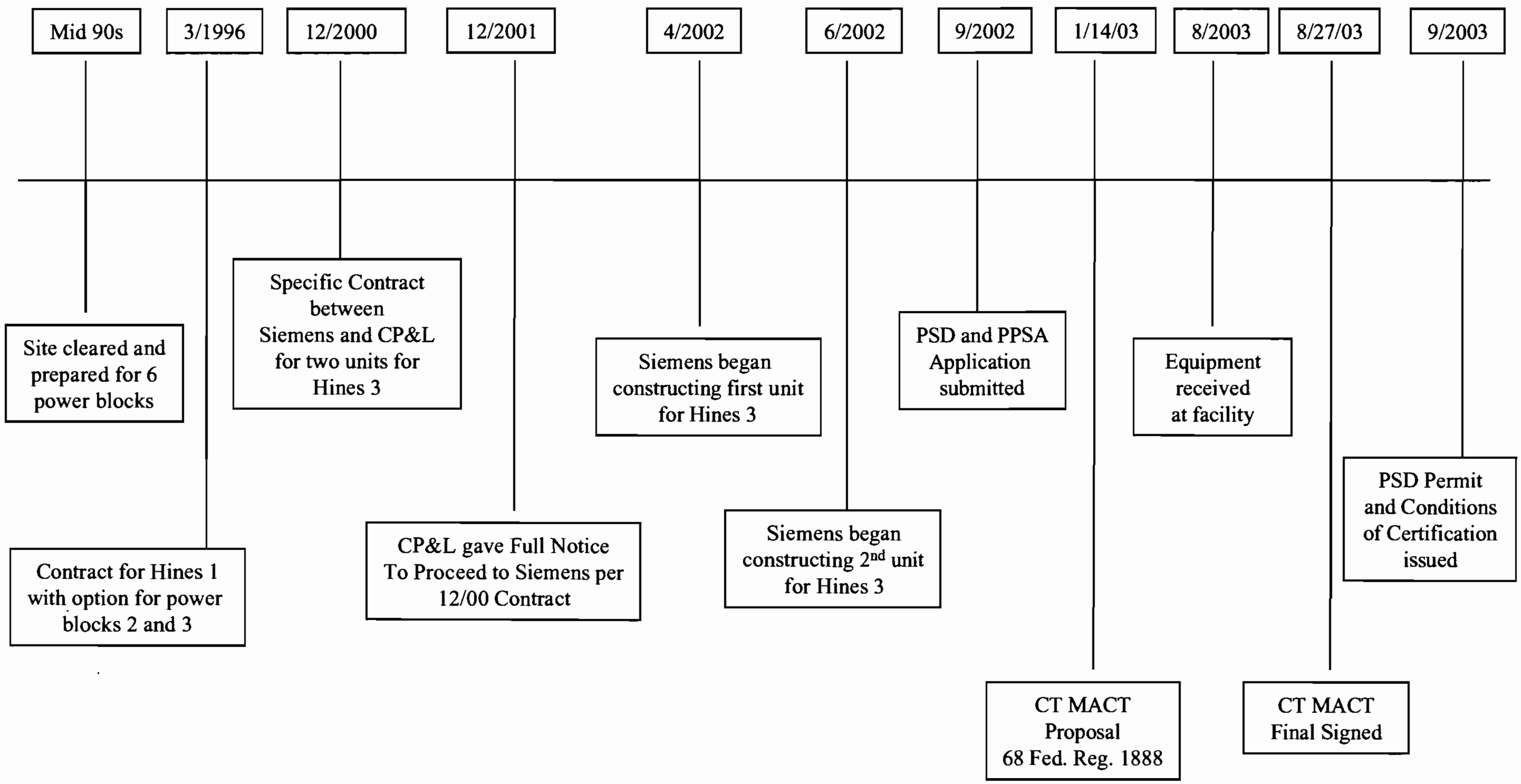
Please let me know if you have any questions or need any additional information.

Thanks

Jamie Hunter
Lead Environmental Specialist
Progress Energy Florida
P.O. Box 14042, BB1A
St. Petersburg, FL 33733
office: 727-826-4363
fax: 727-826-4216

# HINES POWER BLOCK 3 TIMELINE

DRAFT 5/24/04



Generation Equipment Supply Contract
No. XTB0000281
Carolina P&L
and Siemens Westinghouse
Date of Contract Dec 19, 2000

Def -

Full Notice to Proceed - due Feb 1, 2002 - otherwise
22 automatically terminated.
→ Need Full Notice to Proceed.

30 Limited Notice to Proceed - due Dec 1, 2001 - otherwise
automatically terminated.

33 Notice is required to be in writing

GC3. After issuance of ~~the~~ LNTP (limited Notice to proceed)
and after issuance of FNTP (full Notice to Proceed) by
CP&L, Supplier ..... shall be in conformance w/
the Contract Documents & to the extent authorized by
the applicable notice to proceed ..... do all things
necessary or incidental to the furnishing and
delivering to CP&L of two (2) 501F Combustion
Turbine Generator Units
Except as provided in Article GC12, entitled
Contract Termination - CP&L's Convenience of
these General Conditions, CP&L shall have no
obligation to Seller unless and until a LNTP is
issued to Seller by CP&L

GC12. Contract Termination - CP&L's Convenience
CP&L reserves the right to cancel the Contract for its Convenience. In the event of such Cancellation, CP&L will pay the Supplier the applicable Termination Fee as set forth . . . Exhibit E

ExE Failure to deliver LNTP 10% of Contract price
(would already have paid 5% so looks like real penalty of 5%)
and looks like payment of 5% due at Contract signing, 5% due at LNTP
10% more due 3/1/02

by 9/2003 had already paid 90% / cum term price due 100%
Permit ... 9/2003

Delivery Schedule - April 1 2003 STA
- July 1 2003 STB
Delivery to US Port of Entry - Not to Site
Delivery to Site + 1 month each

Does not include unloading and field erection of equipment (1A.4)

Actual on-site installation - Not in delivery
Contract.
Separate Contract for installation : : looks like
Contract issued to - S & B Bibb (A & E [redacted])
date executed -
whatever locates to Hines 3 -

Joint venture Contract between Progress & S & B Bibb

## Vielhauer, Trina

**From:** Linero, Alvaro
**Sent:** Tuesday, February 01, 2005 3:22 PM
**To:** Vielhauer, Trina
**Subject:** RE: Commenced Construction

Trina. Help!

Teresa put together attached chart on commencing construction.

See column on far right, second page, 62-210, Permits required.

Looks like a permit is required prior to beginning construction. But to commence construction means you have all permit AND have done one or more of three things:

beginning on-site construction

Binding contract to do it

Initiating change in operation

It's looking like they can e.g. buy a turbine, but not enter into a binding contract to install it. That would mean they commenced construction per NSPS but not per our SIP rule.

I don't know how we would enforce on a start of construction (not physical construction) without a permit unless they told us or we found out about it.

I think some States actually allow physical start of construction (i.e. as opposed to just binding agreements) while applications are considered. I wouldn't suggest going that far.

I think we should allow binding agreements before permits because they probably already occur, they promote economic efficiency, etc. Now they would have to understand that they could have to renegotiate some details related to BACT!

Looks like this would require a rule change.

Let me know if you think some can do a design/build contract before getting a permit. It would facilitate reasonable assurance in some cases.

Al.

**Vielhauer, Trina**

| | |
|---|---|
| **From:** | Gibson, Victoria |
| **Sent:** | Friday, October 08, 2004 7:20 AM |
| **To:** | Vielhauer, Trina |
| **Subject:** | FW: Tuesday Meeting |

-----Original Message-----
From: Hunter, John J (Jamie) [mailto:John.Hunter@pgnmail.com]
Sent: Thursday, October 07, 2004 3:38 PM
To: Gibson, Victoria
Subject: RE: Tuesday Meeting

I have copied the original mater contract for Hines 1 (with options for Hines 2 and 3) to a CD. I will give to Robert tomorrow at the FCG Air meeting.

-----Original Message-----
From: Gibson, Victoria [mailto:Victoria.Gibson@dep.state.fl.us]
Sent: Thursday, October 07, 2004 2:43 PM
To: Vielhauer, Trina; robertm@hgslaw.com; Halpin, Mike; Hunter, John J (Jamie)
Subject: FW: Tuesday Meeting
Importance: High

Hi,

Would 10:00 am on Tuesday morning be alright with everyone?

Thank you.

Victoria Gibson, Administrative Secretary
For Trina Vielhauer, Bureau Chief
DEP/Bureau of Air Regulation
victoria.gibson@dep.state.fl.us
850-921-9504

-----Original Message-----
From: Vielhauer, Trina
Sent: Wednesday, October 06, 2004 6:16 PM
To: Gibson, Victoria
Subject: Fw:

Trina Vielhauer

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Sent from my BlackBerry Wireless Handheld

-----Original Message-----
From: Vielhauer, Trina <Trina.Vielhauer@dep.state.fl.us>
To: 'ROBERTM@hgslaw.com' <ROBERTM@hgslaw.com>
Sent: Wed Oct 06 18:10:53 2004
Subject: Re:

I think tuesday would be ok. I was just trying to get to it quickly. I'll double-check mike's calendar (vickie- can you check his outlook
calendar) and
confirm. Would morning or afternoon be better? Trina Vielhauer

--------------------------
Sent from my BlackBerry Wireless Handheld

-----Original Message-----
From: ROBERT A MANNING <ROBERTM@hgslaw.com>
To: Vielhauer, Trina <Trina.Vielhauer@dep.state.fl.us>
CC: John.Hunter@pgnmail.com <John.Hunter@pgnmail.com>
Sent: Wed Oct 06 16:26:56 2004
Subject: Re:

I'm in Tampa on Monday, but if that is the best day for you, I could make arrangements to have the documents available. Otherwise, I'm back in Tallahassee for the rest of next week. Please let me know what you prefer. Thanks, Robert.

Robert Manning
Hopping Green & Sams, P.A.
123 South Calhoun Street
Tallahassee, Florida 32314
HG&S website: http://www.hgslaw.com.
Reception desk: (850) 222-7500
Direct line: (850) 425-2263
Fax: (850) 224-8551
E-mail: robertm@hgslaw.com
Assistant: Lou Ann Kuehlke
Lou Ann's direct line: (850) 425-3420



>>> "Vielhauer, Trina" <Trina.Vielhauer@dep.state.fl.us> 10/6/2004
4:09:32 PM >>>
Mike halpin is the engineer on the hines project. He is out of town this week but we could do the review monday afternoon. Would that work? I'll try to come over too.
Trina Vielhauer

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Sent from my BlackBerry Wireless Handheld

## Vielhauer, Trina

**From:** Vielhauer, Trina
**Sent:** Tuesday, June 08, 2004 9:10 AM
**To:** 'page.lee@epa.gov'
**Cc:** Halpin, Mike; DeAngelo, Gregory
**Subject:** FW: Palm Beach Power document

Lee,
Good morning. I wanted to let you know that you may get a call from Robert Manning - an attorney representing Progress Energy Hines. We met with them Friday regarding "commencing construction" for purposes of YYYY.

They accepted a PSD permit [without comment] in September 2003 that contained a statement that they are a "new source" under YYYY and that they would not be commencing construction until after January 14, 2003.

We met with them last week and they are trying to argue that they have contracts in place so they have "commenced construction". We have indicated we do not agree with that assessment, that they did not have their PSD permit so they could not have "commenced construction". We referred to the background documents for Subpart A, PSD program documents discussing "commenced construction" as well as the Palm Beach Power situation which you and Mike Halpin discussed some time ago [see attached- only for your reference and was not provided to Hines].

When we told them we did not agree with their interpretation they asked for a name in Region 4 and we gave them yours. This is just a "heads up" that you might get a telephone call.

If you have any questions or need any additional information, please call me, Greg DeAngelo or Mike Halpin. You can reach all of us at 850/488-0114.

Trina Vielhauer

-----Original Message-----
From: Page.Lee@epamail.epa.gov [mailto:Page.Lee@epamail.epa.gov]
Sent: Tuesday, September 03, 2002 3:41 PM
To: Halpin, Mike
Cc: Little.James@epamail.epa.gov
Subject: Re: Palm Beach Power

Mike: 63.42(c) says that no person may "begin actual construction" or reconstruction of a major HAP source unless the source has been specifically regulated or exempted from regulation in section 112, or the permitting authority has made a final and effective case by case MACT determination - which is equivallent to the PSD requirement to have all necessary preconstruction approvals.

The definitions and interpretations in part 63 are always (we try) consistent and parallel with the PSD definitions and interpretations. Therefore, the PSD interpretation of commenced construction should apply to part 63 sources as well.

"Halpin, Mike"
<Mike.Halpin@dep.state.fl.us>

09/03/2002 02:01 PM

To: Lee Page/R4/USEPA/US@EPA
cc: James Little/R4/USEPA/US@EPA
Subject: Palm Beach Power

Hello Lee -
I was hoping that you have had some time to think about my request concerning the applicability of New Source MACT (case by case) for the Palm Beach Power Project. As we had discussed with Jim Little, the issue appears to deal with whether the facility has commenced contruction(?). I believe that concerning a PSD interpretation of that question, Jim has provided me with adequate guidance. Due to Florida regs, I am under a 30-day clock for determining whether the applicant has submitted a complete application (I'm on day 19). If you believe that it will take more time than this to draw your conclusion, please advise at your earliest convenience. I can be reached at 850-921-9519 if necessary.

Thanks
Mike Halpin (Florida)

Hopping Green & Sams
Attorneys and Counselors

# MEMORANDUM

TO: Trina Vielhauer

FROM: Robert Manning

RE: Progress Energy Florida, Hines Power Block 3
MACT Applicability Timeline

DATE: June 1, 2004

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As I mentioned last week, attached are three documents that will hopefully be helpful in preparing for this Friday's meeting to discuss CT MACT applicability at Hines 3:

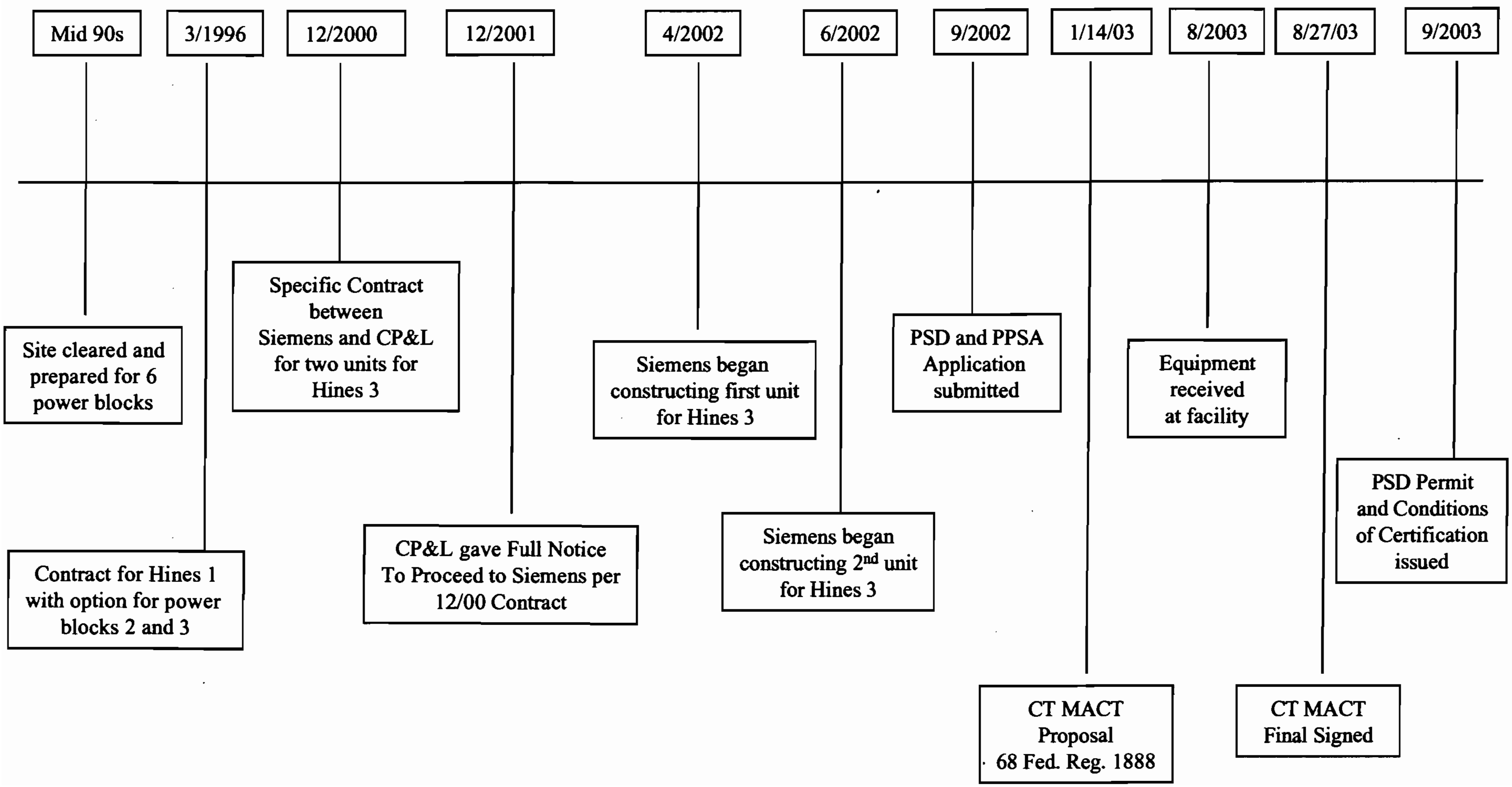
(1) A timeline showing relevant dates;
(2) A letter from Florida Power & Light (FP&L) to EPA regarding applicability; and
(3) A letter from EPA to FP&L confirming that sufficient contractual obligations were in place to avoid applicability.

We will bring additional relevant contract documents to Friday's meeting. Thank you and we look forward to seeing you on Friday. If you have any questions in the meantime, please give me a call.

Post Office Box 6526 Tallahassee, Florida 32314 123 South Calhoun Street (32301) 850.222.7500 850.224.8551 fax www.hgslaw.com

# HINES POWER BLOCK 3 TIMELINE

DRAFT 5/24/04



-File/B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

1421 PEACHTREE ST., N. E.
ATLANTA, GEORGIA 30309

January 26, 1976

Mr. W. J. Barrow, Jr.
Florida Power and Light Company
Post Office Box 013100
Miami, Florida 33101

Re: Florida Power and Light Company
Willow Creek Site of Manatee County Station

Dear Mr. Barrow:

This is in response to your letter dated January 20, 1976, requesting a determination as to whether Florida Power and Light's Manatee County Station qualifies as an "existing source" under Title 40 of the Code of Federal Regulations (CFR), Part 60, Subpart D.

The information you submitted on January 21, 1976, and the information attached to your letter of January 20, 1976, evidence binding contracts for the purchase of equipment (Boiler Unit #1 and Boiler Unit #2) prior to the effective date of EPA's Regulations on Standards of Performance for New Stationary Sources. Based on this information, it is our opinion that the Manatee County Station is not a "new source" within the meaning of §111 (a) (2) of the Clean Air Act Amendments of 1970, and is therefore exempt from the federal requirements imposed under 40 CFR 60.

This exemption is limited to the above described and in no way relieves Florida Power and Light from compliance with other federal, state or local pollution abatement requirements.

Sincerely,

Frances E. Phillips

Frances E. Phillips
Regional Counsel

cc: Mr. Jay Landers
Dr. J. P. Subramani

FLORIDA POWER & LIGHT COMPANY

January 20, 1976

Mr. G. T. Helms, Jr., PE
Deputy Director,
Air and Hazardous Material Division
U. S. Environmental Protection Agency
Region IV
1421 Peachtree Street, N.E.
Atlanta, Georgia 30309

Dear Mr. Helms:

The intent of this letter is to have a ruling on the status of FP&L's Manatee Plant according to the Environmental Protection Agency's Regulations on Standards of Performance for New Stationary Sources. It is FP&L's position that this plant qualifies as an existing source under these regulations which became effective on August 17, 1971. We quote the following:

Title 40 Subpart A - General Provisions

§60.1 Applicability

Except as provided in Subparts B and C, the provisions of this part apply to the owner or operator of any stationary source which contains an affected facility, the construction or modification of which is commenced after the date of publication in this part of any standard (or, if earlier, the date of publication of y proposed standard) applicable to that facility.

§60.2 Definitions

(i) "Commenced" means with respect to the definition of "new source" in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or <u>that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification</u>. (Emphasis applied)

It is FP&L's contention that the Manatee Plant correlates with the EPA's definition of an existing plant, since "contractual obligations to undertake and complete a continuous program of construction" were entered into prior to August 17, 1971 for this particular plant. These "contractual obligations" are documented by the following, copies of which are attached:

1) April 11, 1969 - FPL letter to Westinghouse Electric Corporation ordering two turbine generators.

2) April 21, 1970 - Foster Wheeler Corporation letter confirming FPL verbal order for one boiler April 13, 1970, and setting forth proposal detail including an option on No. 2 boiler.

3) Sept. 1, 1970 - FPL letter to Mid-Valley, Inc. retaining this company as the engineering and construction firm. Authority given to proceed with engineering.

4) March 26, 1971 - FPL letter to Foster Wheeler Corporation exercising option to purchase No. 2 boiler.

To put these four correspondences in the proper framework, it is important to understand FP&L's basic procedure for the construction of a fossil fuel plant. First the two most important components, the turbine generator and the boiler, are selected and purchased. Once these purchases have been made then an architectural engineering firm is contracted to engineer and construct the plant according to the specifications of the turbine generator and boilers. Because of the magnitude of these initial choices, the company is committed to a program of construction.

If we can supply any additional information, please let us know.

Very truly yours,

W. J. Barrow, Jr.
Senior Project Coordinator

WJB:jr:CCC:sa

Enclosures

* Personal and Confidential

Not Scanned
will remain w/file

1050234-006-AC

FLORIDA ELECTRIC POWER COORDINATING GROUP, INC. (FCG)
405 REO STREET, SUITE 100 ◦ (813) 289-5644 ◦ FAX (813) 289-5646
TAMPA, FLORIDA 33609-1094



July 21, 2004

*Privileged and Confidential*
*Attorney-Client Communication*

Michael Cooke, Division Director
Division of Air Resource Management
Florida Department of Environmental Protection
111 South Magnolia Drive
Tallahassee, Florida 32399

Re: Definition of "Commenced Construction" under 40 CFR Part 63

Dear Mr. Cooke:

The Florida Electric Power Coordinating Group, Inc. (FCG)[1] is concerned about the Florida Department of Environmental Protection's (DEP) recent interpretation that, for purposes of applicability under 40CFR Part 63, a construction permit is required before a facility is deemed to have "commenced construction." This is a particularly significant issue because the date a source commences construction determines whether it is defined as "new" or "existing," and new and existing sources are typically subject to very different requirements. The FCG believes that "commenced construction" should be interpreted based on the definitions in 40 CFR Part 63, which does not require a construction permit as a prerequisite, and should be implemented, as directed by EPA, consistently with the New Source Performance Standards (NSPS) program under 40 CFR Part 60. Accordingly, we respectfully request that DEP reconsider its interpretation and no longer base Part 63 applicability on the date a source gets a construction permit.

In general, 40 CFR Part 63 defines a "new" source as one for which "construction or reconstruction commences" after the date a particular NESHAP is proposed in the Federal Register. See, e.g., 63.6(b). 40 CFR Part 63 does not define the phrase "commenced construction," but defines these terms separately as follows:

> "*Commenced* means, with respect to construction or reconstruction of an affected source, that an owner or operator has undertaken a continuous program of construction or reconstruction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or reconstruction."

[1] The FCG is an association of 31 investor-owned, municipally-owned and cooperatively-owned electric utilities engaged in the business of providing electric power to the public in the state of Florida.

> "*Construction* means the on-site fabrication, erection, or installation of an affected source. Construction does not include the removal of all equipment comprising an affected source from an existing location and reinstallation of such equipment at a new location . . . ."

Neither term requires a preconstruction permit. Further, both terms are based on, and nearly identical to, the definitions under 40 CFR Part 60 (NSPS), which EPA has made clear do not require a preconstruction permit. See, e.g., Letter from John B. Rasnic to Joan Cabreza, Region X, dated Oct. 4, 1996 (with citations to prior NSPS determinations); Letter from George T. Czerniak, EPA to Tenneci Packaging, Inc., dated June 26, 2997; and Letter from Frances Phillips, EPA to W. J. Barrow, Jr., FPL, dated January 26, 1976. Significantly, EPA has expressly stated that Part 63 is intended to be implemented consistently with Part 60:

> The key to the EPA's approach to developing the proposed general provisions for part 63 was to reuse as much as possible the technical and policy approaches associated with the existing general provisions in parts 60 and 61. This approach maintains consistency with the EPA's past regulatory perspectives developed for other national standards required by section 111 and former section 112 of the Act. . . . In addition to carrying forward precedents wherever possible, this approach takes advantage of the familiarity that the regulated community and compliance personnel have with the existing general provisions. Consequently, implementation of the new general provisions would occur with the least burden on the user communities

58 Fed. Reg. 42760 (Aug. 11, 1993) (preamble to proposed Part 63 rule).

Applicability under Part 63, therefore, is determined based on when a source begins "a continuous program of construction . . . or has entered into a contractual obligation" to do so, and not on the date it receives a construction permit.

Confusion has apparently arisen regarding the determination of when construction commences under Part 63 because of similar definitions under the Prevention of Significant Deterioration (PSD) program, which prohibits a source from commencing construction before it obtains a construction permit. In other words, under the PSD program, commence construction determinations do not determine PSD applicability (except at the start of the program 25 years ago). Rather, the definitions were developed and are used to dictate what activities a source can undertake prior to obtaining its permit, as well as to confirm that the source initiates and undertakes a continuous program of construction. This makes sense for PSD because it is a single regulation that has applied to all source categories from the beginning; it is not promulgated piecemeal as new source-category regulations are developed, as in Parts 60 (NSPS) and 63 (NESHAPs). And the PSD program is designed to ensure that there is not a prolonged delay in either the initiation or continuation of actual construction, whereas NSPS and NESHAPs are not concerned with this timing.

Under Part 63, as well as Part 61 (older NESHAPs) and Part 60 (NSPS), however, the terms "commence" and "construction" are used for different purposes: (1) primarily, to determine whether a particular source-category regulation applies, based on the *Federal Register* proposal date, and (2) similar to PSD, what activities a source can undertake prior to obtaining its permit. For applicability purposes under Parts 60 and 63, therefore, the date a source receives its permit should not be relevant; applicability, by definition, is based on when a source begins "a continuous program of construction . . . or has entered into a contractual obligation" to do so. Finally, the one difference in the definitions under Part 60 (NSPS) and Part 63 (NESHAP) is the insertion of the phrase "on-site" at the beginning of the definition of "construction" under Part 63. A review of the background information, EPA determinations and caselaw shows that this is simply a clarification in Part 63 to show what activities a source can undertake before getting its permit (for example, it can conduct off-site engineering and design work), and is not intended to change the applicability-determination analysis. See, e.g., "General Provisions for 40 CFR Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories," Background Information for Promulgated Regulations, P. 2-63, 64 (Feb. 1994).

DEP's interpretation is relevant to applicability determinations for all NESHAPs (and came to light recently during discussions regarding the applicability of the NESHAP for combustion turbines) and is thus of great interest to the FCG and all other sources subject to Part 63. Accordingly, the FCG requests that DEP reconsider its interpretation and implement Part 63 in accordance with existing definitions and direction by EPA.

We would appreciate an opportunity to discuss this issue with you further, and will be contacting you within the next couple of weeks in this regard. If you have any questions in the meantime, please contact me at (813) 228-4560 or Robert Manning at Hopping Green & Sams, P.A. at (850) 425-2263.

Sincerely,

Robert Manning

for Laura Crouch
Chair, FCG Air Subcommittee

cc: Trina Vielhauer, DEP
Pat Comer, DEP
Lee Page, EPA Region 4
FCG Air Subcommittee
Robert Manning, HGS

Hopping Green & Sams

Attorneys and Counselors



September 2, 2004

Michael Cooke, Division Director
Division of Air Resource Management
Florida Department of Environmental Protection
111 South Magnolia Drive
Tallahassee, Florida 32399

Re: Relevant Documents for MACT Applicability

Dear Michael:

As you requested, enclosed are several relevant pages from the Progress Energy contract for its Hines 3 units. As I mentioned, Progress Energy is required to keep its contracts confidential and I am providing these pages to you with the understanding that they will not be disclosed to a third party without written approval from Progress Energy.

If you have any questions about these documents or need additional information, please contact me at your earliest convenience. I appreciate your assistance with this matter and look forward to the Department's determination.

Sincerely,

Robert Manning

Robert A. Manning

RAM:lk

Enclosures

Post Office Box 6526 Tallahassee, Florida 32314 123 South Calhoun Street (32301) 850.222.7500 850.224.8551 fax www.hgslaw.com

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# GENERATION EQUIPMENT SUPPLY CONTRACT

NO. XTB0000281

BETWEEN

CAROLINA POWER & LIGHT COMPANY

AND

SIEMENS WESTINGHOUSE POWER CORPORATION

FOR

COMBUSTION TURBINE EQUIPMENT

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## CONTRACT NO. XTB0000281

This Generation Equipment Supply Contract, dated this 15th day of December, 2000, is between CAROLINA POWER & LIGHT COMPANY, a North Carolina corporation, with offices at 411 Fayetteville Street Mall, Raleigh, North Carolina 27601 (hereinafter referred to as "CP&L") and SIEMENS WESTINGHOUSE POWER CORPORATION, a Delaware corporation, with offices at the Quadrangle, 4400 Alafaya Trail, Orlando, Florida 32826-2399, (hereinafter referred to as "Supplier"). CP&L and Supplier may be referred to herein individually as a "Party" and collectively as the "Parties".

WITNESSETH:

WHEREAS, CP&L desires Supplier to supply certain Equipment and Services to CP&L; and,

WHEREAS, Supplier is agreeable to provide such Equipment and Services; and,

WHEREAS, CP&L and Supplier desire to define their rights and obligations in connection with the supply of such Equipment and Services;

NOW THEREFORE, in consideration of the above premises and respective covenants and undertakings hereinafter set forth, and intending to be legally bound hereby, CP&L and Supplier agree as follows:

## GENERAL CONDITIONS

GC.1 CONTRACT DOCUMENTS. It is understood and agreed that these General Conditions, attached Exhibits, Specification, and Appendices; and any Change Orders or Amendments issued by CP&L, and specifications and engineering data furnished by the Supplier and accepted in writing by CP&L, are each included in this Contract and the Work shall be done in accordance therewith.

GC.2 DEFINITIONS. Words, phrases, or other expressions used in these Contract Documents shall have meanings as follows:

1. "Actual Unit Exhaust Flow Rate" shall mean the actual Unit exhaust flow rate as established in the Performance Test.

2. "Actual Unit Exhaust Temperature" shall mean the actual Unit exhaust temperature as established in the Performance Test.

22. "Full Notice to Proceed" or "FNTP" shall mean the Notice from CP&L to Supplier releasing the Supplier to commence all Work under this Contract. The schedules for Delivery of Drawings and Plans, Delivery of Major Components and Provisional Acceptance are based upon the Full Notice to Proceed being given by CP&L on February 1, 2002. If the Full Notice to Proceed is not given by CP&L by February 1, 2002, this Contract shall be automatically terminated and such termination shall be deemed a termination for CP&L's convenience in accordance with Article GC.12, entitled CONTRACT TERMINATION – CP&L's CONVENIENCE, of these General Conditions and neither party shall have any further liability to the other under this Contract for either or both Units.

23. "Guaranteed Unit Emissions" shall mean the emissions that are identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

24. "Guaranteed Unit Exhaust Flow Rate" shall mean the Unit exhaust flow rate that is identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

25. "Guaranteed Unit Exhaust Temperature" shall mean the Unit exhaust temperature that is identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

26. "Guaranteed Unit Net Electrical Output" shall mean the Unit net electrical output that is identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

27. "Guaranteed Unit Net Heat Rate" shall mean the Unit net heat rate that is identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

28. "Guaranteed Unit Sound Level Limits" shall mean the Unit sound level limits that are identified to be guaranteed by Supplier for the Unit in Exhibit B of the Contract Documents.

29. "Jobsite" or "Site" shall have the meaning stated in Article 1A.1 of the Specification.

30. "Limited Notice To Proceed" or "LNTP" shall mean the Notice from CP&L to Supplier releasing the Supplier to commence the manufacturing of the Units under this Contract. The schedules for Delivery of Major Components and Provisional Acceptance are based upon the Limited Notice to Proceed being given by CP&L no later than December 1, 2001. If the Limited Notice to Proceed is not given by CP&L on or before December 1, 2001, this Contract shall be

automatically terminated and such termination shall be deemed a termination for CP&L's convenience in accordance with Article GC.12, entitled CONTRACT TERMINATION – CP&L's CONVENIENCE, of these General Conditions.

31. "Major Component(s)" shall mean those components of the Units set forth in Exhibit A.

32. "Minor Components" shall mean the remaining components and sub-assemblies of each Unit that are not listed in Exhibit A.

33. "Notice" shall mean any notice provided for or required hereunder and shall be deemed to have been sufficiently served if the notice shall be in writing and (1) hand delivered (as evidenced by written acknowledgment by the Party receiving said notice or by sworn certification of the Party delivering said notice) or (2) by facsimile transmission (as evidenced by the printed receipt from the facsimile machine attached to a copy of the notice faxed. Fax transmittals sent outside of receiving Party's normal business hours will be considered received the first business Day after transmittal.) or (3) delivered by a nationally recognized overnight courier (as evidenced by written acknowledgment by the Party receiving said notice or by the appropriate shipping documentation) or (4) deposited in the United States mail, postage prepaid, certified with return receipt requested, addressed as follows:

To CP&L: See Article GC.2.10, entitled CP&L, above.
To Supplier: See Article GC.2.43, entitled Supplier, below.

or to such other persons or addresses as either of the Parties shall substitute from time to time by giving notice as herein required. If notice is by US mail as provided in (4) above, delivery/service of said notice shall be deemed given five (5) Days after such notice is deposited in the US mail, certified return receipt requested, with proper postage affixed thereto (assuming the notice has been sent to the correct address). If notice is by the procedures identified as (1), (2), and (3) above, notice shall be effective upon delivery/receipt.

34. "Parties" or "Party" shall mean the parties or one of the parties who are signatory to this Contract (CP&L and the Supplier).

35. "Performance Guarantees" shall mean the Guaranteed Unit Net Electrical Output, the Guaranteed Unit Net Heat Rate, the Guaranteed Unit Exhaust Flow Rate and the Guaranteed Unit Exhaust Temperature.

36. "Performance Test" shall mean the Performance Test in accordance with Article 4.2, entitled Performance Testing, in Exhibit B.

properly and fairly classified under one or more unit price items of the Contract.

b. Agreed to unit prices not otherwise included in (a) above.

c. Agreed to fixed prices.

GC.19.2 Decreased Work. If a modification decreases the amount of work to be done, such decrease shall not constitute the basis for a claim for damages or anticipated profits on work affected by such decrease. CP&L shall retain the option of receiving credit for decreased work by one of the following methods, such method to be determined by CP&L before the work is omitted:

a. In accordance with applicable unit prices set forth in the Contract, if the additional and/or extra work is of a type and character which can be properly and fairly classified under one or more unit price items of the Contract.

b. Agreed to unit prices not otherwise included in (a) above.

c. Agreed to fixed prices.

GC.20 LAWS AND REGULATIONS. The Contract Price is based on the Site being in Bartow, Florida and the Supplier shall observe and comply with all federal, state, and local ordinances, laws, codes, and regulations and all other applicable requirements of authorities having jurisdiction over the Work at such Site, including but not limited while on CP&L's Site to the Federal "Safety and Health Regulations for Construction," OSHA Safety and Health Standards, Title 29 CFR, Part 1926-Construction Industry and Part 1910-General Industry Standards identified as applicable to construction and all references incorporated therein. The Contract Price is based on laws and regulations in effect at the time of execution of this Contract. However, the Supplier's requirements regarding sound level and air emission levels shall only be the guarantee requirements stated in this Contract, in lieu of applicable laws and regulations. If the actual Site is not in Bartow, Florida and any changes in the Units or the other Work are required as a result thereof, the Parties will negotiate in good faith and execute an appropriate Change Order or Contract Amendment therefor.

GC.21 TOXIC SUBSTANCES. If the Work under this Contract involves toxic substances, the provisions of Florida Statutes Chapter 84-223 (Right to Know Law), the Florida Solid Waste Act of 1988, and the Federal Hazardous Communications Standards shall apply. Toxic substances are defined in the Florida statute as ". . . any chemical substance or mixture in a gaseous, liquid, or solid state, if such substance or mixture causes a significant risk to safety or health during, or as a proximate result of, any customary or reasonably foreseeable handling or use and which is listed in the Florida Substance List . . . and which is manufactured, produced, used, applied, or stored in the workplace."

The Supplier is responsible for determining if any substances furnished, used, applied, or stored under this Contract are within the provisions of the referenced statute, the Federal

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**IN WITNESS WHEREOF,** the authorized representatives of both Parties have executed this Contract as of the latest date set forth below:

**CAROLINA POWER AND LIGHT COMPANY**

By: ______________________

Title: Group President - Energy Ventures

Date: December 19, 2000

**SIEMENS WESTINGHOUSE POWER CORPORATION**

By: ______________________

Title: Vice President Southeast Region

Date: 12/18/00

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## Section 1A - GENERAL REQUIREMENTS AND SCOPE OF THE WORK

1A.1 GENERAL. This section covers the general description, scope of the Work, and supplementary requirements for generation equipment and materials, and services included under these specifications.

The Contract for the equipment and materials covered by these specifications is based on the equipment and materials being incorporated in FPC's Hines Energy Complex Project. The site is located in South-Central Polk County, Florida. The site is bounded on the west by C.R. 555, on the north by C.R. 640, and the east by US 17/US 98. Delivery of equipment is available by truck from C.R. 555 via C.R. 640 and US 17/US 98. There is a rail siding on the west side of the site.

1A.2 WORK INCLUDED UNDER THESE SPECIFICATIONS. The Work under these specifications shall include furnishing F.O.B. Hines Energy Complex Project site two Siemens Westinghouse W501F combustion turbine generator Units and providing miscellaneous materials and services complete as specified herein and in accordance with the Contract Documents.

The Schedule is based on two combustion turbines and all required balance-of-plant achieving Provisional Acceptance by April 1, 2004 based on FNTP being given on February 1, 2002.

The equipment will be tested in accordance with Exhibit B after erection to demonstrate its ability to operate under the conditions and fulfill the guarantees. If the tests indicate that the equipment fails to meet guaranteed performance, the Supplier shall repair or replace the equipment in accordance with the Terms and Conditions stated in the Contract, or following such efforts, pay applicable Liquidated Damages if the equipment fails to meet guaranteed output, heat rate, exhaust flow and/or exhaust temperature in accordance with the Terms and Conditions of the Contract.

The Supplier shall provide drawings and other engineering data, manufacturer's field services, tools, instruction manuals, recommended spare parts list, miscellaneous materials and services, and shall participate in design and coordination conferences at the start of the project and throughout the project as required, all as specified herein. Equipment, materials, and accessories furnished shall be delivered to the Hines Energy Complex Project site where they will be received, unloaded, stored, and erected under separate contract. Deficiencies shall be sufficient cause to reject equipment f.o.b. carrier. Unloading from carrier and storing will not constitute acceptance.

The Supplier shall provide equipment designed for a useful life of at least 30 years, designed in accordance with standard utility practice, and capable of supporting cycling service and a high plant capacity factor.

BEST AVAILABLE COPY

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## Exhibit E
## Payment and Termination Fee Schedule

| Project Month | Date | Milestone | Payment % of Contract Price | Cumulative Payment % of Contract Price | Cumulative Termination % of Contract Price (2) |
|---|---|---|---|---|---|
| -12 | 12/01/2000 | Contract Execution (1) | [redacted] | | |
| -11 | 01/01/2001 | | | | |
| -10 | 02/01/2001 | | | | |
| -9 | 03/01/2001 | | | | |
| -8 | 04/01/2001 | | | | |
| -7 | 05/01/2001 | | | | |
| -6 | 06/01/2001 | | | | |
| -5 | 07/01/2001 | | | | |
| -4 | 08/01/2001 | | | | |
| -3 | 09/01/2001 | | | | |
| -2 | 10/01/2001 | | | | |
| -1 | 11/01/2001 | | | | |
| 0 | 12/01/2001 | Limited Notice to Proceed (1) | | | |
| 1 | 01/01/2002 | | | | |
| 2 | 02/01/2002 | Full Notice to Proceed | | | |
| 3 | 03/01/2002 | Progress Payment | | | |
| 4 | 04/01/2002 | | | | |
| 5 | 05/01/2002 | | | | |
| 6 | 06/01/2002 | Progress Payment | | | |
| 7 | 07/01/2002 | | | | |
| 8 | 08/01/2002 | | | | |
| 9 | 09/01/2002 | Progress Payment | | | |
| 10 | 10/01/2002 | | | | |
| 11 | 11/01/2002 | | | | |
| 12 | 12/01/2002 | | | | |
| 13 | 01/01/2003 | | | 40.00% | 50.00% |
| 14 | 02/01/2003 | | [redacted] | | |
| 15 | 03/01/2003 | CTG #1 Ex-Works | | | |
| 16 | 04/01/2003 | CTG #1 US Port of Entry | | | |
| 17 | 05/01/2003 | Deliver CTG # 1 to Site | | | |
| 18 | 06/01/2003 | CTG #2 Ex-Works | | | |
| 19 | 07/01/2003 | CTG #2 US Port of Entry | | | |
| 20 | 08/01/2003 | Deliver CTG #2 to Site | | | |
| 21 | 09/01/2003 | | | | |
| 22 | 10/01/2003 | | | | |
| 23 | 11/01/2003 | | | | |
| 24 | 12/01/2003 | | | | |
| 25 | 01/01/2004 | | | | |
| 26 | 02/01/2004 | | | | |
| 27 | 03/01/2004 | | | | |
| 28 | 04/01/2004 | Scheduled Provisional Acceptance | | | |
| 29 | 05/01/2004 | | | | |
| 30 | 06/01/2004 | Final Acceptance | | | |

Notes:
1. These milestone payments require wire transfer payment within five (5) working days of the date listed
2. Siemens Westinghouse retains title to equipment for termination prior to delivery

1B.5 PRESHIPMENT INSPECTION. CP&L reserves the right to inspect the equipment prior to shipment, and determine if equipment is suitable for shipment. CP&L shall not be responsible for shipment delays due to unsuitable equipment or preshipment problems.

The Supplier shall notify CP&L and the Engineer of all shipments not less than 30 days prior to the date of shipment to allow CP&L to inspect the equipment if so desired.

1B.6 SHIPMENTS. Shipments to the plant site shall be consigned to the following locations:

Rail Shipments:

**LATER**

Truck Shipments:

**LATER**

The Supplier shall discuss with CP&L the routing of shipments and shall route the same as indicated by CP&L provided freight rates are no greater than by other routes.

1B.7 SHIPPING NOTICE. The Supplier shall submit to CP&L two copies of shipping notices describing each shipment of material or equipment. The shipping notices shall be mailed to arrive approximately 3 days ahead of the estimated shipment arrival. The addressee for each shipping notice will be determined later.

1B.8 MATERIALS LIST. The Supplier shall prepare and submit with the first shipping notice two copies of an itemized materials list covering all material and equipment furnished under these specifications. The materials list shall be in sufficient detail to permit an accurate determination of the completion of shipment.

1B.9 HAZARDOUS MATERIALS. All shipments of hazardous materials shall be identified on the materials list. A copy of the hazardous materials documentation required by the article entitled HAZARDOUS MATERIALS in the General Conditions shall be included with the materials list and shall also be included with the shipping papers attached to the shipment.

1B.10 CORRECTION OF ERRORS. Equipment and materials shall be complete in all respects within the limits herein outlined. All errors or omissions required to be corrected in the field shall be done by the manufacturer or his duly authorized representative at the Supplier's expense.

1B.11 NUMBERING SYSTEM. The Engineer will establish an identification numbering system to provide consistent numbering throughout the generating unit. All electrical devices, control equipment, valves, and other items of similar nature shall be permanently identified with the identification number supplied by the Engineer. For instrumentation, the Supplier will use its standard nomenclature and labeling. A cross reference between the KKS

THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re:
Florida Power Corporation
Polk County, Florida

OGC CASE NO.:____________________
FDEP Draft Permit No.: PSD-FL-330
Project No. 1050234-006-AC

________________________________________/

**NOTICE OF EXPIRATION OF ENLARGEMENT OF TIME**

Florida Power Corporation (doing business as Progress Energy Florida, Inc.), by and through undersigned counsel, hereby acknowledges the expiration of its Request for Enlargement of Time to file a petition for formal administrative proceedings in accordance with Chapter 120, Florida Statutes. On March 21, 2003, Progress Energy Florida filed a Request for Enlargement of Time until April 25, 2003, in response to the "Intent to Issue PSD Permit" and accompanying "Draft Permit," (Draft Permit No. PSD-FL-330), "Technical Evaluation and Preliminary Determination" and "Draft BACT Determination" regarding construction of Power Block 3 at the existing Hines Facility, located in Polk County, Florida. Following discussions with Department representatives, Progress Energy Florida and the Department have come to agreement on the issues involved in the above-referenced PSD permit, as reflected in the attached document. Accordingly, conditioned on the Department's issuance of the Final Permit consistent with the agreement, Progress Energy Florida does not intend to renew its Request for Enlargement of Time.

RECEIVED

APR 28 2003

BUREAU OF AIR REGULATION

RESPECTFULLY SUBMITTED this 25th day of April, 2003.

By: Robert A. Manning

Robert A. Manning
Florida Bar ID No. 0035173
Hopping Green & Sams, P.A.
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314
(850) 222-7500
(850) 224-8551 Facsimile

Attorneys for PROGRESS ENERGY FLORIDA, INC.

**CERTIFICATE OF SERVICE**

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by U.S. Mail to Al Linero, Bureau of Air Regulation, Department of Environmental Protection, 2600 Blair Stone Road, MS 5505, Tallahassee, FL 32399-2400; and W. Douglas Beason, Office of the General Counsel, Department of Environmental Protection, 3900 Commonwealth Blvd., Room 353-A, Tallahassee, FL 32399-2600 this 25th day of April, 2003:

Robert A. Manning

Robert A. Manning

# DRAFT PERMIT R01

**PERMITTEE:**

Progress Energy Florida
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

*Authorized Representative:*
Roger Zirkle, Plant Manager – Hines Energy Complex

| |
|---|
| Hines Energy Complex, Power Block 3<br>Project No. 1050234-006-AC<br>Air Permit No. PSD-FL-330<br>SIC No. 4911<br><br>Expires: June 30, 2007 |

**PROJECT AND LOCATION**

This permit authorizes the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

**STATEMENT OF BASIS**

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

**CONTENTS**



^ DRAFT ^ DRAFT

_______________________________ _______________

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

## FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 3), the plant will have a total generating capacity of approximately 1,560 MW.

## NEW AND MODIFIED EMISSIONS UNITS

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

| ID | Emission Unit Description |
|---|---|
| 016 | Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG) |
| 017 | Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG) |

*{Permitting Note: The Hines Energy Complex, Power Block 3 (Power Block 3, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 3A and CT 3B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}*

## REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). This project may trigger a case-by-case MACT determination pursuant to Section 112(j) of the Act – the "MACT hammer." (See Appendix YYYY.)

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

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

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

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

## PERMITTING AUTHORITY

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

## COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

## APPENDICES

The following Appendices are attached as part of this permit.

| | |
|---|---|
| Appendix AL | Acronym List |
| Appendix BD | Final BACT Determinations and Emissions Standards |
| Appendix CF | Citation Format and Definitions |
| Appendix GC | General Conditions |
| Appendix GG | NSPS Subpart GG Requirements for Gas Turbines |
| Appendix SC | Standard Conditions |
| Appendix XS | Semiannual NSPS Excess Emissions Report |
| Appendix YYYY | NESHAP Subpart YYYY and 112(j) MACT Hammer |

## REVIEWING AND PROCESSING SCHEDULE

| | |
|---|---|
| September 4, 2002 | Received permit application and fee |
| November 7, 2002 | Department's request for additional information (via Office of Siting Coordination's sufficiency questions) |
| December 19, 2002 | Received response to sufficiency questions |
| February 19, 2003 | Received report documenting commercial, residential, and industrial growth since August 7, 1977 |
| February 19, 2003 | Application complete |
| March 5, 2003 | Distributed Notice of Intent to Issue and supporting documents |
| March 21, 2003 | Notice of Intent to Issue published in the *Lakeland Ledger* |

## RELEVANT DOCUMENTS

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

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Technical Evaluation and Best Available Control Technology (BACT) Determination
- Department's Intent to Issue

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

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

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

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

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

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

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

This section of the permit addresses the following emissions units.

**Emission Units 016 and 017**

**Description**: Emission units 016 and 017 each consist of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

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

**Generating Capacity**: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

**Controls**: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, $PM/PM_{10}$, SAM, $SO_2$ and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

**Stack Parameters**: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

| Fuel | Heat Input Rate (HHV) | Compressor Inlet Temp | Exhaust Temperature | Exit Velocity | Flow Rate |
|---|---|---|---|---|---|
| Gas | 1,830 MMBtu/hour | 59 °F | 190 °F | 59.2 ft/sec | 1,009,487 acfm |
| Oil | 1,932 MMBtu/hour | 59 °F | 270 °F | 67.0 ft/sec | 1,139,394 acfm |

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

## APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, $PM/PM_{10}$, sulfuric acid mist (SAM), $SO_2$, and VOC. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

## EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of

170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

6. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen when natural gas is fired and 7.0 ppmvd corrected to 15% oxygen when distillate oil is fired. [Rule 62-4.070(3), F.A.C.]

**PERFORMANCE RESTRICTIONS**

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

   c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

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

**EMISSIONS STANDARDS**

9. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | 5 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| $PM/PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| $SAM/SO_2$ [f] | Fuel specifications. |

   a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data. The Department shall revise the CO emissions standards following any future installation of an oxidation catalyst pursuant to Condition No. 6 of this section.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

f. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}* [Rule 62-212.400(BACT), F.A.C.]

### STARTUP, SHUTDOWN, AND MALFUNCTION EMISSIONS

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

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

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

13. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section.

    a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period.

    b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block.

    c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

    d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the notification requirements specified in Condition No. 26 of this section.

    e. All periods of data excluded for any startup, shutdown, oil-to-gas fuel switch, or documented malfunction shall be consecutive for each episode. Periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed six hours in any 24-hour block period during which a cold startup occurred. For all other 24-hour block periods, periods of data excluded for all startups, shutdowns, oil-to-gas fuel switches, or documented malfunctions shall not exceed four hours.

    f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented. Best operating practices shall be used to minimize hourly emissions that occur during episodes of startup, shutdown, oil-to-gas fuel switching, or documented malfunction.

    [Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

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

## EMISSIONS PERFORMANCE TESTING

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

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | *Procedure for Collection and Analysis of Ammonia in Stationary Sources*<br>This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. |

| Method | Description of Method and Comments |
|---|---|
| 7E | *Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)* |
| 9 | *Visual Determination of the Opacity of Emissions from Stationary Sources*<br>The test shall be conducted for a minimum of 30 minutes. |
| 10 | *Determination of Carbon Monoxide Emissions from Stationary Sources*<br>This method shall be based on a continuous sampling train. |
| 18 | *Measurement of Gaseous Organic Compound Emissions by Gas Chromatography*<br>(Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. |
| 20 | *Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines* |
| 25A | *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer* |

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

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

17. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of $PM/PM_{10}$ and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

    a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

    b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

*{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

19. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

   a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

   b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

   c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

   Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

**CONTINUOUS MONITORING REQUIREMENTS**

20. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

   a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The CO monitor shall be a dual range monitor. The span for the lower range shall not be greater than 50 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

   b. *NOx Monitors.* The NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm. The span for the upper range shall be set at a level that provides for accurate measurement during startups and shutdowns.

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

d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures $CO_2$ on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

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

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section.

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

*{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}* [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

21. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

**RECORDS AND REPORTS**

23. Monitoring of Operation: To demonstrate compliance with the fuel consumption and sulfur content limits of Condition No. 8 of this section, the permittee shall monitor and record the rates of consumption and sulfur content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

24. Frequency of Recordkeeping: Condition No. 20 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

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

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

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

26. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition No. 13 of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

28. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 13 and 14 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

APR 17 2003

RECEIVED
APR 21 2003
BUREAU OF AIR REGULATION

4 APT-APB

A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for the FPC - Hines facility dated March 5, 2003 The preliminary determination is for the proposed construction and operation of two combined cycle combustion turbines (CTs) with a total nominal generating capacity of 530 MW to be located near Bartow, FL. The combustion turbines proposed for the facility are Siemens Westinghouse 501FD units and will be coupled with unfired heat recovery steam generating units. The CTs will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CTs will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 720 hours per year. Total net emissions increases from the proposed project are above the thresholds requiring PSD review for nitrogen oxides ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), particulate matter ($PM/PM_{10}$) and volatile organic compounds (VOC).

We have reviewed the PSD permit application, preliminary determination and draft PSD permit for the Power Block 3 project described above. On June 7, 2001, the Florida Department of Environmental Protection (FDEP) issued a final PSD permit to FPC Hines for an identical combined cycle combustion project referred to as Power Block 2. It is our understanding that the Power Block 2 project is still under construction. Additionally, the Power Block 3 PSD permit application was submitted to FDEP in September 2002, less than 15 months from the issuance of the Power Block 2 project. Given the short period of time between the two projects and since the Power Block 2 project has not yet begun operation, FDEP should consider evaluating these to projects together with regards to PSD applicability.

If you have any questions regarding this comment, please direct them to Katy Forney at 404-562-9130.

Sincerely,

James W. Little

James Little
Acting Section Chief,
Air Permits Section

cc: G. DeAngelo
O. Nelson
B. Oven, DEP
G. Kissel, SWD
L. Kosky, Golder
J. Bunyak, NPS

Progress Energy

April 8, 2003

RECEIVED
APR 09 2003
BUREAU OF AIR REGULATION

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Hines Energy Complex – Power Block 3
Project No. 1050234-006-AC
Draft Permit No. PSD-FL-330
Comments on Draft Permit

Please find below Florida Power Corporation's (now doing business as Progress Energy Florida) comments on the above referenced draft permit. A copy of the draft permit, with the requested changes (in ~~strikethrough~~ and underline format) outlined in the comments below, is enclosed for reference.

**Comments:**

- Please change the name where referenced from "Florida Power" to "Progress Energy Florida."
- Please change the Authorized Representative from Bruce Baldwin to Roger Zirkle, who is the Title V Responsible Official for this facility.
- For clarification, please remove the words "for the given operating conditions" from the Permitting Note located under the PROJECT AND LOCATION section on page 1, since the operating conditions are not specified.
- Based on the May 27, 1999 PSD permit modification for Power Block 1, the nominal MW reference should be 500, not 485. This should be corrected in the FACILITY DESCRIPTION section (page 2), as well as the total MW description for Power Blocks 1-3.
- Correct the reference under the REGULATORY CLASSIFICATION section (page 2) from Appendix YY to Appendix YYYY.

**Progress Energy Florida, Inc.**
P.O. Box 14042
St. Petersburg, FL 33733

- Add language to Condition 4 (page 6) to clarify that DLN and water injection tuning are performed "in conjunction with any post-combustion emissions control equipment" to achieve permitted emissions levels.

- Add language to Condition 6 (page 6) to specify separate emission target levels for natural gas and oil firing. The oil firing emission level should be twice that of the natural gas level to retain the same ratio as the uncontrolled levels.

- The ammonia emission limit for fuel oil (Condition 9, page 7) should be changed from 5 to 9. This reflects the need to inject higher levels of ammonia during oil firing, as the NOx emission levels are higher at the SCR inlet when firing oil.

- Add clarifying language to Condition 9.a. (page 7) to reflect requirements of Condition 6 and allow for a period of time that the CO emission limits are allowed to be exceeded while additional CO emission controls are installed and tested.

- Add clarifying language to Condition 9.d. (page 8) to reflect that the 5 ppmvd target level is based on firing natural gas.

- Modify heading prior to Condition 10 (page 8) for clarification.

- Modify language in Condition 13.d. (page 9) to be consistent with the intent of Condition 26. Also, note that Condition 26 is modified to be consistent with intent in Condition 13.d.

- Strike the first sentence in Condition 13.e. (page 9). Periods of data exclusion are already limited sufficiently; therefore, there is no reason to further limit them.

- Add language to Condition 13.e. (page 9) to allow for the additional time required for "cold" start-ups, as outlined in Condition 13.a.

- The reference to "15% oxygen" in Condition 20.a. and 20.b. (page 11) should be removed, as the monitor spans are based on actual stack concentrations, not corrected values.

- The upper range span for the NOx monitor referenced in Condition 20.b. (page 11) should be changed from 30 to 200. This will allow emission during start-up/shutdown/malfunctions to be monitored. Also, note that the CO monitor referenced in Condition 20.a. will likely be a dual range monitor with an upper span of 1200 ppm for this same reason.

- Modify language in Condition 20.g. (page 11) to remove reference to "steam blows", as this is not applicable to this permit. Also, remove the language after the first two sentences, as this is redundant of language already included in Condition 13.

- Clarify language in Condition 26 (page 14) to remove reference to Condition 14, as malfunctions are not addressed by Condition 14. Also, clarify acceptable means of notification (language moved from Condition 13.d.).

Please contact me if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services
Progress Energy Florida

jjh/JJH062

Enclosure

c(w/enc): Greg DeAngelo, FDEP - Tallahassee

# DRAFT PERMIT

**PERMITTEE:**

Progress Energy Florida ~~Florida Power~~
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

*Authorized Representative:*
~~Bruce Baldwin, Vice President – Combustion Turbine Operations~~
Roger Zirkle, Plant Manager – Hines Energy Complex

Hines Energy Complex, Power Block 3
Project No. 1050234-006-AC
Air Permit No. PSD-FL-330
SIC No. 4911

Expires: June 30, 2007

**PROJECT AND LOCATION**

This permit authorizes the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values ~~for the given operating conditions~~.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

**STATEMENT OF BASIS**

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

**CONTENTS**



^ DRAFT ^ DRAFT

Howard L. Rhodes, Director
Division of Air Resources Management

(Date)

## FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a ~~485~~ 500 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 3), the plant will have a total generating capacity of approximately ~~1,545~~ 1,560 MW.

## NEW AND MODIFIED EMISSIONS UNITS

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

| ID | Emission Unit Description |
|---|---|
| 016 | Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG) |
| 017 | Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG) |

*{Permitting Note: ~~Florida Power~~ The Hines Energy Complex Power Block 3 (Power Block 3, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 3A and CT 3B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}*

## REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). This project may trigger a case-by-case MACT determination pursuant to Section 112(j) of the Act – the "MACT hammer." (See Appendix ~~YY~~ YYYY.)

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

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

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

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

## PERMITTING AUTHORITY

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

## COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

## APPENDICES

The following Appendices are attached as part of this permit.

| | |
|---|---|
| Appendix AL | Acronym List |
| Appendix BD | Final BACT Determinations and Emissions Standards |
| Appendix CF | Citation Format and Definitions |
| Appendix GC | General Conditions |
| Appendix GG | NSPS Subpart GG Requirements for Gas Turbines |
| Appendix SC | Standard Conditions |
| Appendix XS | Semiannual NSPS Excess Emissions Report |
| Appendix YYYY | NESHAP Subpart YYYY and 112(j) MACT Hammer |

## REVIEWING AND PROCESSING SCHEDULE

| | |
|---|---|
| September 4, 2002 | Received permit application and fee |
| November 7, 2002 | Department's request for additional information (via Office of Siting Coordination's sufficiency questions) |
| December 19, 2002 | Received response to sufficiency questions |
| February 19, 2003 | Received report documenting commercial, residential, and industrial growth since August 7, 1977 |
| February 19, 2003 | Application complete |
| ^ DRAFT | Distributed Notice of Intent to Issue and supporting documents |
| ^ DRAFT | Notice of Intent to Issue published in ^ DRAFT |

## RELEVANT DOCUMENTS

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

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Technical Evaluation and Best Available Control Technology (BACT) Determination
- Department's Intent to Issue

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

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

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

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

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

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

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

This section of the permit addresses the following emissions units.

**Emission Units 016 and 017**

**Description**: Emission units 016 and 017 each consist of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

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

**Generating Capacity**: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

**Controls**: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/$PM_{10}$, SAM, $SO_2$ and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

**Stack Parameters**: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

| Fuel | Heat Input Rate (HHV) | Compressor Inlet Temp | Exhaust Temperature | Exit Velocity | Flow Rate |
|---|---|---|---|---|---|
| Gas | 1,830 MMBtu/hour | 59 °F | 190 °F | 59.2 ft/sec | 1,009,487 acfm |
| Oil | 1,932 MMBtu/hour | 59 °F | 270 °F | 67.0 ft/sec | 1,139,394 acfm |

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

## APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, PM/$PM_{10}$, sulfuric acid mist (SAM), $SO_2$, and VOC. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

## EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of

170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned, in conjunction with any post-combustion emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

6. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen when natural gas is fired and 7 ppmvd corrected to 15% oxygen when oil is fired.

## PERFORMANCE RESTRICTIONS

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

   b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

   c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

   d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

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

EMISSIONS STANDARDS

9. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | ~~5~~ 9 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| PM/$PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| SAM/$SO_2$ [f] | Fuel specifications. |

   a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. Should the permittee be unable to meet these emission limits, the provisions of Condition 6 will apply. The permittee is allowed to exceed these emission limits until the CO catalyst has been installed and tested. After installation of the CO catalyst, these emission limits are revised to those referenced in Condition 6. *{Permitting Note: A 24-hour* *compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen when firing natural gas based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

f. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}* [Rule 62-212.400(BACT), F.A.C.]

### ~~EXCESS~~ STARTUP/SHUTDOWN AND MALFUNCTION EMISSIONS

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

11. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup,

shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

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

13. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section.

    a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period.

    b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block.

    c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

    d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that meets the "malfunction notification" requirements outlined in Condition No. 26. ~~is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.~~

    e. ~~All periods of data excluded for any startup, shutdown, oil-to-gas fuel switches, or documented malfunction shall be consecutive for each episode.~~ Periods of data excluded for all startup, shutdown, oil-to-gas fuel switches, or documented malfunctions shall not exceed four hours in any 24-hour block (or six hours when the 24-hour block period includes a cold startup).

    f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

    [Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

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

## EMISSIONS PERFORMANCE TESTING

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

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | *Procedure for Collection and Analysis of Ammonia in Stationary Sources*<br>This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. |

| Method | Description of Method and Comments |
|---|---|
| 7E | *Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)* |
| 9 | *Visual Determination of the Opacity of Emissions from Stationary Sources*<br>The test shall be conducted for a minimum of 30 minutes. |
| 10 | *Determination of Carbon Monoxide Emissions from Stationary Sources*<br>This method shall be based on a continuous sampling train. |
| 18 | *Measurement of Gaseous Organic Compound Emissions by Gas Chromatography*<br>(Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. |
| 20 | *Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines* |
| 25A | *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer* |

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

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

17. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of $PM/PM_{10}$ and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.
    a. *Visible Emissions*. Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*
    b. *Ammonia*. Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

*{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

19. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

    a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

    b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

    c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

    Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

### CONTINUOUS MONITORING REQUIREMENTS

20. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 50 ppm~~, as corrected to 15% oxygen~~.

    b. *NOx Monitors.* The NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than ~~30~~ 200 ppm~~, as corrected to 15% oxygen~~.

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

d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures $CO_2$ on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

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

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, and DLN tuning~~, and steam blows~~. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section. ~~All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.~~

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

*{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}* [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

21. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

### RECORDS AND REPORTS

23. Monitoring of Operation: To demonstrate compliance with the fuel consumption and sulfur content limits of Condition No. 8 of this section, the permittee shall monitor and record the rates of consumption and sulfur content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

24. Frequency of Recordkeeping: Condition No. 20 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

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

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

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

26. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Conditions ~~Nos~~No. 13 ~~or 14~~ of this section, the permittee shall notify the Compliance Authority by telephone, facsimile transmittal, or electronic mail. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

28. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 13 and 14 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

Florida Power
A Progress Energy Company

RECEIVED
MAR 28 2003
BUREAU OF AIR REGULATION

March 27, 2003

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Hines Energy Complex – Power Block 3
Project No. 1050234-006-AC
Draft Permit No. PSD-FL-330
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published in the Lakeland Ledger on March 21, 2003.

Please contact me if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

jjh/JJH059

Enclosure

c(w/enc): Greg DeAngelo, FDEP - Tallahassee

P.O. Box 14042
St. Petersburg, FL 33733

# AFFIDAVIT OF PUBLICATION
## THE LEDGER
## Lakeland, Polk County, Florida

RECEIVED
MAR 28 2003
BUREAU OF AIR REGULATION

**Case No ....................**

**Attach Notice Here**

**STATE OF FLORIDA)**
**COUNTY OF POLK)**

Before the undersigned authority personally appeared Sandra Heath, who on oath says that she is Assistant Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

......................Notice Of Intent..........................................

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in the matter of......Permit No. PSD-FL-330....................................

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in the.................................................................................

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Court, was published in said newspaper in the issues of.......................

............................3-21; 2003.........................................

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Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed Sandra Heath

Sandra Heath
Assistant Classified Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 21st

day of March A.D. 20 03

Patricia Ann Rouse
Notary Public
PATRICIA ANN ROUSE

PATRICIA ANN ROUSE
MY COMMISSION # CC 976018
EXPIRES: October 17, 2004
Bonded Thru Notary Public Underwriters

(Seal)
My Commission Expires..........................

LL111248 H713 Progress Energy

## PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft permit No. PSD-FL-330

Florida Power Hines Energy Complex, New Combined Cycle Power Block 3
Polk 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 Florida Power. The permit is one of several authorizations needed to construct a nominal 530 megawatt (MW) combined cycle gas project at the Florida Power Hines Energy Complex, which is located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida. In accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.), Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter (PM/PM10), sulfur dioxide (SO2), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. Bruce Baldwin; Vice President - Combustion Turbine Operations. The applicant's address is Florida Power, P.O. Box 140442 - MAC BB1A, St. Petersburg, FL 33733-4042.

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following new equipment: two 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired heat recovery steam generators, and a common steam-electrical generator (190 MW). The gas turbines will be fired primarily with natural gas, with up to the equivalent of 720 hours per year per turbine of very low sulfur distillate oil allowed as a restricted alternate fuel. The gas turbines will only be operated in combined cycle mode. Additional equipment includes two 125-foot stacks.

During operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. Emissions of CO, PM/PM10, SAM, SO2, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. When the turbines are firing natural gas, the permit will limit emissions of CO to 10 parts per million by volume on a dry basis (ppmvd) and emissions of NOx to 2.5 ppmvd, both as corrected to 15 percent oxygen. The Department determines that these control techniques and equipment represent BACT in accordance with Rule 62-212.400, F.A.C. Emissions standards for oil firing, VOC emissions, and ammonia slip are presented in the draft permit on file with the Department.

Based on the the initial application, the maximum potential annual emissions from the combined cycle gas turbines that comprise new Power Block 3 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

| Pollutant | Maximum Tons Per Year | PSD Significant Emission Rate Tons Per Year | PSD Review Required? |
|---|---|---|---|
| CO | 744 | 100 | Yes |
| Lead (Pb) | 0.02 | 0.6 | No |
| NOx | 267 | 40 | Yes |
| PM/PM10 | 121/121 | 15/25 | Yes |
| SO2 | 137 | 40 | Yes |
| SAM | 21 | 7 | Yes |
| VOC | 57 | 40 | Yes |

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels. Therefore, multi-source modeling was not required. The predicted impacts in the Chassahowitzka National Wilderness Area are less than the applicable PSD Class I significant impact levels; therefore, multi-source Class I PSD increment modeling was not required.

Based on the required analysis, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen 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), F.S., 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, F.A.C.

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

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

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

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

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8318
Telephone: (813)744-6100
Fax: (813)744-6084

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850)488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

H713 - 3-21; 2003

Florida Department of
# Environmental Protection

## Memorandum

TO: Trina Vielhauer, Chief, Bureau of Air Regulation by aay 3/5

THROUGH: Al Linero, Administrator - New Source Review Section aay 3/5

FROM: Greg DeAngelo

DATE: March 5, 2003

SUBJECT: Florida Power Hines Energy Complex
Project No. 1050234-006-AC
PSD Permit No. 330
Power Block 3; New 530 MW "2-on-1" Combined Cycle Gas Turbine

Attached for your review are the following items:

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

The Technical Evaluation and Preliminary Determination provides a detailed description of the project, rule applicability, BACT determinations and permit conditions. The P.E. certification briefly summarizes the proposed project. The project is subject to power plant siting. Day No. 90 is May 19, 2003. I recommend your approval of the attached Draft Permit for this project.

AAL/gpd

Attachments

## P.E. CERTIFICATION STATEMENT

### PERMITTEE

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

| Florida Power Hines Energy Complex<br>Project No. 1050234-006-AC<br>Air Permit No. PSD-FL-330 |
|---|

### PROJECT DESCRIPTION

The applicant proposes to construct a "2-on-1" nominal 530 megawatt (MW) combined cycle Power Block 3 consisting of two Siemens Westinghouse 501 FD gas turbine-electrical generator sets, an automated gas turbine control system, and an unfired heat recovery steam generator (HRSG). In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems. Each gas turbine will fire natural gas as the primary fuel and very low sulfur distillate oil as a restricted alternate fuel. (Restricted to the equivalent of 720 hours per year per unit.) Additional equipment includes two 125-foot combined cycle stacks.

CO, $PM/PM_{10}$, and VOC will be minimized by the efficient, high-temperature combustion of natural gas and distillate oil. Emissions of SAM and $SO_2$ will be minimized by firing natural gas and restricting the amounts of very low sulfur distillate oil. NOx emissions will be reduced with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing. In combination with these NOx controls, a selective catalytic reduction (SCR) system further reduces NOx emissions. These controls are determined to represent the Best Available Control Technology (BACT). No alternative method of operation is allowed; the units are only permitted for non-augmented, combined cycle operation. The draft permit includes the following standards for emissions of CO, NOx, VOC, and ammonia.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO | 10 | 20 | 24 hour block |
| NOx | 2.5 | 10 | 24 hour block |
| VOC | 2 | 10 | 3 hours |
| Ammonia | 5 | 5 | 3 hours |

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

Gregory P. DeAngelo, P.E.
Registration Number: 58591

3/5/03
(Date)

**Department of**
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

March 5, 2003

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Bruce Baldwin, Vice President – Combustion Turbine Operations
Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Re: Project No. 1050234-006-AC (Air Permit No. PSD-FL-330)
Florida Power Hines Energy Complex
New 530 Megawatt Combined Cycle Power Block 3

Dear Mr. Baldwin:

Florida Power applied for a Prevention of Significant Deterioration (PSD) air permit to construct a new 530 megawatt "2-on-1" combined cycle gas turbine unit at the existing Florida Power Hines Energy Complex. The Florida Department of Environmental Protection ("the Department") has reviewed the application and additional information submitted and prepared the enclosed intent to issue permit package. The enclosures include the following: the "Intent to Issue Air Construction Permit," the "Public Notice of Intent to Issue Air Construction Permit," the "Technical Evaluation and Preliminary Determination" (draft Best Available Control Technology determinations), and the draft permit.

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

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Al Linero, Administrator of the New Source Review Section, at the above letterhead address. If you have any questions, please call Mr. Greg DeAngelo at (850)921-9506.

Sincerely,

for Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/AAL/gpd

Enclosures

In the Matter of an
Application for Permit by:

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

*Authorized Representative:*
Bruce Baldwin, Vice President – Combustion Turbine Operations

Project No. 1050234-006-AC
Draft Air Permit No. PSD-FL-330
Florida Power Hines Energy Complex
New Combined Cycle Power Block 3

## INTENT TO ISSUE PSD PERMIT

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

The applicant, Florida Power, applied on September 4, 2002 to the Department for a PSD permit for a new 530 megawatt combined cycle gas turbine project (Power Block 3) at the existing Florida Power Hines Energy Complex, located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida.

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

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

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

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

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

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen 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), F.S., 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, F.A.C.

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

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

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

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

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

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

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

Executed in Tallahassee, Florida.

for Trina Vielhauer, Chief
Bureau of Air Regulation

**CERTIFICATE OF SERVICE**

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation and Preliminary Determination, Draft Best Available Control Technology Determination, and the DRAFT permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 3/5/03 to the persons listed:

Mr. Bruce Baldwin, Florida Power *
Mr. John J. Hunter, Florida Power
Mr. Ken Kosky, Golder Associates Inc.
Mr. Jerry Kissel, SWD
Mr. Gregg Worley, EPA Region 4
Mr. John Bunyak, NPS

Clerk Stamp

**FILING AND ACKNOWLEDGMENT FILED**, on this date, pursuant to §120.52, Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Victoria Gibson March 5, 2003
(Clerk) (Date)

## PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft Permit No. PSD-FL-330

Florida Power Hines Energy Complex, New Combined Cycle Power Block 3
Polk 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 Florida Power. The permit is one of several authorizations needed to construct a nominal 530 megawatt (MW) combined cycle gas project at the Florida Power Hines Energy Complex, which is located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida. In accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.), Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter ($PM/PM_{10}$), sulfur dioxide ($SO_2$), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. Bruce Baldwin, Vice President – Combustion Turbine Operations. The applicant's address is Florida Power, P.O. Box 140442 – MAC BB1A, St. Petersburg, FL 33733-4042.

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following new equipment: two 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired heat recovery steam generators, and a common steam-electrical generator (190 MW). The gas turbines will be fired primarily with natural gas, with up to the equivalent of 720 hours per year per turbine of very low sulfur distillate oil allowed as a restricted alternate fuel. The gas turbines will only be operated in combined cycle mode. Additional equipment includes two 125-foot stacks.

During operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. Emissions of CO, $PM/PM_{10}$, SAM, $SO_2$, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. When the turbines are firing natural gas, the permit will limit emissions of CO to 10 parts per million by volume on a dry basis (ppmvd) and emissions of NOx to 2.5 ppmvd, both as corrected to 15 percent oxygen The Department determines that these control techniques and equipment represent BACT in accordance with Rule 62-212.400, F.A.C. Emissions standards for oil firing, VOC emissions, and ammonia slip are presented in the draft permit on file with the Department.

Based on the initial application, the maximum potential annual emissions from the combined cycle gas turbines that comprise new Power Block 3 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

| Pollutant | Maximum Tons Per Year | PSD Significant Emission Rate Tons Per Year | PSD Review Required? |
|---|---|---|---|
| CO | 744 | 100 | Yes |
| Lead (Pb) | 0.02 | 0.6 | No |
| NOx | 267 | 40 | Yes |
| $PM/PM_{10}$ | 121/121 | 15/25 | Yes |
| $SO_2$ | 137 | 40 | Yes |
| SAM | 21 | 7 | Yes |
| VOC | 57 | 40 | Yes |

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels. Therefore, multi-source modeling was not required. The predicted impacts in the Chassahowitzka National Wilderness Area are less than the applicable PSD Class I significant impact levels; therefore, multi-source Class I PSD increment modeling was not required.

Notice for Newspaper

Based on the required analyses, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen 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), F.S., 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, F.A.C.

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

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

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8318
Telephone: (813)744-6100
Fax: (813)744-6084

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850)488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

Notice for Newspaper

# TECHNICAL EVALUATION
# &
# PRELIMINARY DETERMINATION
# (Draft BACT Determinations)

**PROJECT**

Florida Power – Hines Energy Complex
Power Block 3 Combined Cycle Project

Project No. 1050234-006-AC
Draft Permit No. PSD-FL-330

**COUNTY**

Polk County

**APPLICANT**

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, Florida 33733-4042

**PERMITTING AUTHORITY**

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

DEPARTMENT OF ENVIRONMENTAL PROTECTION
FLORIDA

March 5, 2003

*Filename: 330 TEPD.doc*

## TABLE OF CONTENTS

This document describes the overall project, identifies applicable air pollution regulations, provides the rationale for draft determinations of the Best Available Control Technology (BACT), establishes emissions standards, presents a review of the air quality impact analysis, and makes a preliminary determination to issue the air permit. It is organized by the following sections.

## 1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

Facility Address

Florida Power – Hines Energy Complex
One Power Plaza (263 13th Ave S)
St. Petersburg, FL 33701

Authorized Representative:
Bruce Baldwin, Vice President – Combustion Turbine Operations

Processing Schedule

- Received application on September 4, 2002;
- Additional information requested on November 7, 2002;
- Received additional information on December 19, 2002 and February 19, 2003; application deemed complete.

Facility Description and Location

The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. The facility currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 485 megawatt (MW) combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 heat recovery steam generators (HRSGs), and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit.

Power Block 3 ("the project") is a new "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 MW, and it will consist of two 170 MW gas turbine-electrical generator sets, two unfired HRSG sets, and a single 190 MW steam turbine-electrical generator. The plant will have a total generating capacity of approximately 1,545 MW following completion of Power Block 3. *{Note: Throughout this document, the electrical generating capacities represent nominal values for the given operating conditions.}*

Regulatory Categories

*Title III*: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case 112(g) determination of the Maximum Available Control Technology (MACT). This project may trigger a 112(j) case-by-case MACT determination pursuant to the "MACT hammer." (See Section 13, below.)

*Title IV*: The facility operates emissions units subject to the acid rain provisions of the Clean Air Act (CAA, or "the Act").

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

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

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

## 2. PROPOSED PROJECT

Project Description

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following equipment and specifications: two new 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired HRSGs, and a common 190 MW steam turbine-electrical generator.

*Gas Turbine/HRSG Unit*: Each gas turbine/HRSG unit consists of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

*Fuels*: Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternate fuel. Emissions of all pollutants increase with the firing of oil. The applicant requests an aggregated fuel use limit of 27,365,000 gallons of oil per year for both turbines. This is equivalent to 1,000 hours per year per turbine for oil firing, assuming an ambient temperature of 59 °F and the corresponding maximum heat input rate of 1,932 MMBtu/hr.

*Generating Capacity*: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is 530 MW.

*Controls*: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, PM/$PM_{10}$, SAM, $SO_2$ and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

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

*Stack Parameters*: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

**Table 2-1. Combined Cycle Exhaust Characteristics**

| Fuel | Heat Input Rate (HHV) | Compressor Inlet Temp | Exhaust Temperature | Exit Velocity | Flow Rate |
|---|---|---|---|---|---|
| Gas | 1,830 MMBtu/hour | 59 °F | 190 °F | 59.2 ft/sec | 1,009,487 acfm |
| Oil | 1,932 MMBtu/hour | 59 °F | 270 °F | 67.0 ft/sec | 1,139,394 acfm |

Potential Emissions

The project will result in emissions of CO, lead, NOx, PM/$PM_{10}$, $SO_2$, sulfuric acid mist (SAM), and VOC. The following table summarizes the applicant's estimate of the annual emissions in tons per year from the proposed project (gas turbines).

**Table 2-2. Applicant's Estimated Potential Emissions from the Project**

| Pollutant | Maximum Potential Emissions (tons per year) | PSD Significant Emission Rate (tons per year) | PSD Review Required? |
|---|---|---|---|
| CO | 744 | 100 | Yes |
| Lead | 0.02 | 0.6 | No |
| NOx | 267 | 40 | Yes |
| $PM/PM_{10}$ | 121/121 | 15/25 | Yes |
| $SO_2$ | 137 | 40 | Yes |
| SAM | 21 | 7 | Yes |
| VOC | 57 | 40 | Yes |
| Individual HAP (formaldehyde) | 5.7 | 10 [a] | No |
| Total HAPs | 7.3 | 25 [a] | No |

[a] Criteria for case-by-case MACT determination pursuant to Section 112(g) of the Act.

Based on the applicant's estimates, the project requires BACT determinations for emissions of CO, NOx, $PM/PM_{10}$, $SO_2$, SAM, and VOC.

## 3. RULE APPLICABILITY

State Regulations

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

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

Federal Regulations

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

| **Title 40** | **Description** |
|---|---|
| Part 51 | Submittal of Implementation Plans – PSD |
| Part 52 | Approval of Implementation Plans – PSD |

| Title 40 | Description |
|---|---|
| Part 60 | New Source Performance Standards (NSPS) |
| Part 63 | National Emission Standards for Hazardous Air Pollutants (NESHAP) |
| Part 72 | Acid Rain - Permits Regulation |
| Part 73 | Acid Rain - Sulfur Dioxide Allowance System |
| Part 75 | Acid Rain - Continuous Emissions Monitoring |
| Part 76 | Acid Rain - Nitrogen Oxides Emissions Reduction Program |
| Part 77 | Acid Rain - Excess Emissions |

*{Note: Acid rain requirements will be included in the Title V air operation permit. EPA proposed NESHAP for combustion turbines on January 14, 2003 (40 CFR Part 63, Subpart YYYY). See Sections 12 and 13, below, for a discussion of the applicability of 40 CFR Part 63.}*

Description of PSD Applicability Requirements

The Department regulates major air pollution sources in accordance with Florida's PSD program, as defined in Rule 62-212.400, F.A.C. and approved by EPA in the State Implementation Plan. A PSD review is only required in areas that are currently in attainment with the NAAQS for a given pollutant or areas designated as "unclassifiable" for the pollutant. A new facility is considered "major" with respect to PSD if the facility emits or has the potential to emit:

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

For new projects at existing PSD-major sources, each regulated pollutant is reviewed for PSD applicability based on emissions thresholds known as the Significant Emission Rates listed in Table 62-212.400-2, F.A.C. Project emissions exceeding these rates are considered "significant." For each significant pollutant, the applicant must not only employ BACT to minimize emissions but also conduct an appropriate ambient impact analyses. Although a facility may be "major" with respect to PSD for only one regulated pollutant, it may be required to install BACT controls for several significant regulated pollutants.

*{Note: This project is reviewed in accordance with the Federally delegated PSD program because it is subject to electrical power plant site certification.}*

Description of PSD Preconstruction Review Requirements

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

- Any EPA determination of BACT pursuant to Section 169 of the Act, and any emission limitation contained in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP).
- All scientific, engineering, and technical material and other information available to the Department.

- The emission limiting standards or BACT determinations of any other state.
- The social and economic impacts of the application of such technology.

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

The BACT evaluation must be performed for each emissions unit and pollutant under consideration. BACT determinations must result in the selection of control technologies capable of achieving at least the applicable emission standards specified in 40 CFR Part 60 (NSPS) or 40 CFR Part 61 (NESHAP). When reviewing control technologies for regulated pollutants, the Department will favorably consider the control or reduction of other "non-regulated" air pollutants in determining BACT. The Department will also favorably consider control technologies that utilize pollution prevention. These approaches are consistent with EPA's consideration of environmental impacts and strategies for pollution prevention.

The second part of PSD review requires an air quality analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with NAAQS and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility; and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. The applicant must satisfactorily demonstrate that potential project emissions will not significantly contribute to or cause a violation of any ambient air quality standards and will not adversely impact Class I and Class II Areas.

## 4. AVAILABLE INFORMATION

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

- U.S. Department of Energy (DOE) web site information on the Advanced Turbine Systems Project;
- Test data for various similar projects including Calpine facilities in Ontelaunee, Pennsylvania and Decatur, Alabama as well as the AEC facility in McWilliams, Alabama;
- EPA's Alternative Control Techniques Document, "NOx Emissions from Stationary Gas Turbines" (1993);
- DOE report, "Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines" (11/05/99), prepared by Onsite Sycom Energy Corporation;
- AP-42, Section 3.1 for gas turbines (04/00);
- EPA memorandums regarding gas turbines and MACT applicability dated 12/30/99 and 08/21/01; and
- Recently issued permits for the Siemens Westinghouse 501FD gas turbine.

The Department also reviewed recent BACT determinations posted in EPA's RACT/BACT/LAER Clearinghouse. A list of recent BACT determinations regarding similar projects in Florida and the Southeastern United States is provided in Attachment A.

## 5. DRAFT BACT STANDARDS – NITROGEN OXIDES

Discussion of NOx Emissions

A gas turbine is sometimes referred to a "heat engine." In operation, air is compressed, combusted with fuel to produce hot exhaust gases (≈ 2350 °F), and expanded in the turbine section to drive a shaft to produce useful energy. The majority of the energy produced is returned to the compressor and other supporting equipment. The remainder can be used to drive an electrical generator to produce electricity. This power cycle is known as the

Brayton cycle and is commonly referred to as the "simple cycle mode of operation." HRSGs may be added to convert the remaining heat energy of the exhaust gases into steam to drive a steam-electric turbine to produce additional electricity. This additional power cycle is known as the Rankine cycle. Gas turbines with HRSGs are commonly referred to as combined cycle units.

For gas turbines, the primary pollutant of concern is NOx because of the high temperatures. Nearly all of the NOx is emitted as nitric oxide (NO), which is readily oxidized in the exhaust system or the atmosphere to the more stable nitrogen dioxide ($NO_2$) molecule. NOx forms from the dissociation of molecular nitrogen and oxygen into their atomic forms and subsequent recombination into seven different oxides of nitrogen. Three primary mechanisms cause NOx emissions:

- *Thermal NOx* forms in the high temperature area of the gas turbine combustor. It increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen. Less NOx is formed during lean combustion (low fuel-to-air ratio) because the flame temperature is lower.
- *Prompt NOx* is formed in the proximity of the flame front as intermediate combustion products. The contribution of prompt NOx to overall NOx emissions is relatively small in combustors that operate near the stoichiometric air-to-fuel ratio. However, new combustors that operate in lean premix mode generate far less thermal NOx, which makes prompt NOx a greater contributor to overall NOx emissions for these types of units. Therefore, prompt NOx may provide a practical limit for NOx control by lean combustion.
- *Fuel NOx* forms from the oxidation of nitrogen in the fuel. This phenomenon is not important when combusting natural gas or distillate oil fuels, which contain negligible fuel-bound nitrogen.

Uncontrolled NOx emissions from gas turbines may range as high as 600 parts per million by volume, dry (ppmvd), corrected to 15 percent oxygen. The Federal NSPS (40 CFR Part 60, Subpart GG) regulate NOx emissions from large utility gas turbines to 75 ppmvd corrected to 15% oxygen and ISO conditions, which can then be adjusted for the fuel-bound nitrogen content and heat rate of the given unit.

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

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

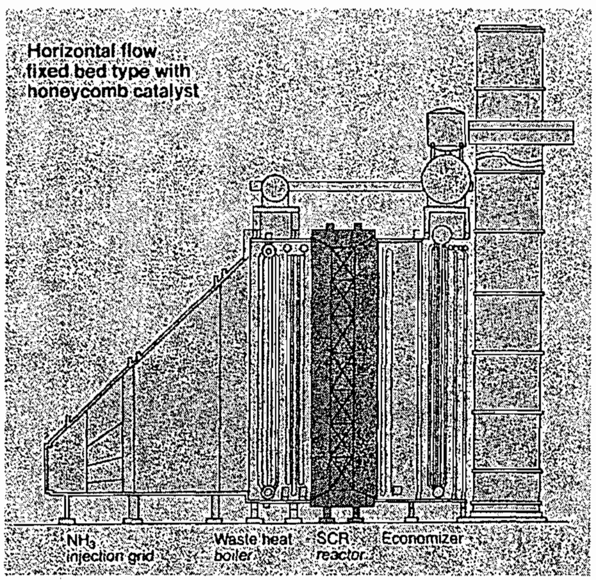
*Lean Premix Combustor Design*: Efforts over the last ten years to minimize NOx emissions from gas turbines have focused on reducing the peak flame temperature for natural gas fired units by staging combustors and premixing fuel and air prior to combustion in the primary zone. The Siemens Westinghouse DLN combustion technology is an example of a lean premix design. The following is a general description of the typical air/fuel combustion modes used to achieve lean premix combustion.

In the primary mode, fuel is supplied only to the primary (diffusion) nozzle to ignite, accelerate, and operate the unit over a range of low-load to mid-load operation and up to a given combustion reference temperature. Once the first combustion reference temperature is reached, operation in a lean-lean mode begins when fuel is also introduced to the secondary nozzles to achieve the second combustion reference temperature. After the second combustion reference temperature is reached, operation in a secondary mode begins by shutting off fuel to the primary nozzle and extinguishing the flame in the primary zone.

Finally, in the lean premix mode, fuel is reintroduced to the primary zone for premixing fuel and air. In some models, such as the General Electric DLN-2.6 can-annular combustor, there is only flame present in the secondary stage even though premixed fuel and air are present in both the primary and secondary nozzles. The Siemens Westinghouse DLN combustors, by contrast, maintain a flame in the primary diffusion nozzle, which leads to slightly higher NOx emissions by comparison.

Lean premix combustion technology results in control efficiencies approaching 95%.

*Wet Injection*: Water or steam can be injected into the primary combustion zone to reduce the flame temperature, resulting in lower NOx emissions. Water injected into this zone acts as a heat sink by absorbing heat necessary to vaporize the water and raise the temperature of the vaporized water to the temperature of the exhaust gas stream. Steam injection uses the same principle, excluding the heat required to vaporize the water. Therefore, much more steam is required (on a mass basis) than water to achieve the same level of NOx control. However, there is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine. The NSPS for gas turbines (40 CFR 60, Subpart GG) were developed around this technology in the late 1970s. Wet injection techniques are generally reserved for oil firing because advanced lean premix combustor designs can achieve much lower NOx emissions for gas firing without wet injection. For oil firing, however, the advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NOx emissions of less than 42 ppmvd when combined with wet injection techniques. Therefore, wet injection remains a viable alternative when firing oil in modern dual fuel combustors. Wet injection results in control efficiencies approaching 75% for oil firing.

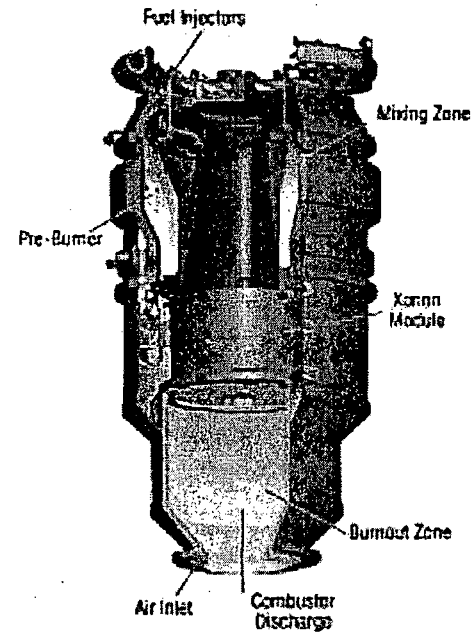



*SCR*: This is an add-on control technology in which ammonia is injected into the exhaust gas stream in the presence of a catalyst bed to combine with NOx in a reduction reaction forming nitrogen and water. The figure below shows the general arrangement of the ammonia injection grid and SCR catalyst with respect to the heat recovery steam generator for a combined cycle unit. The exhaust gas temperature must be maintained between 450 °F and 850 °F for this reaction to proceed satisfactorily. For combined cycle gas turbines, the temperature is within the proper range and conventional catalysts such as vanadium or titanium oxide are acceptable. Ammonia that escapes past the catalyst without reacting with NOx is called "ammonia slip." If the fuel contains significant amounts of sulfur, high levels of ammonia slip can lead to the formation of bisulfates and other particulate matter. Ammonia slip will gradually increase over the life of the system due to degradation of the catalyst. The catalyst is usually replaced every 5 to 7 years although vendors typically guarantee catalysts for about 3 years. SCR is a commercially available, demonstrated control technology currently employed on numerous combined cycle combustion turbine projects permitted with very low NOx emissions (< 2.5/10 ppmvd for gas/oil firing). SCR results in control efficiencies approaching 98%.

*SCONOx™*: This technology is a NOx and CO control system developed by Goal Line Environmental Technologies and is distributed through Alstom Power for large gas turbine projects. Specialized potassium carbonate catalyst beds reduce NOx emissions using an oxidation-absorption-regeneration cycle. The required operating temperature range is between 300 °F and 700 °F, which is within the typical range of exhaust gas from HRSG in a combined cycle gas turbine. SCONOx™ technology (at 2.0 ppmvd) has been used to define the Lowest Achievable Emission Rate (LAER) in non-attainment areas where cost is not a factor in establishing an emissions standard. SCONOx™ systems also oxidize emissions of CO and VOC for additional emission reductions. SCONOx™ can also achieve control efficiencies approaching 98% without the additional ammonia emissions associated with SCR.

*Selective Non-Catalytic Reduction (SNCR)*: This technology works on the same principle as SCR, but in the absence of a catalyst. Ammonia (or urea) is injected directly into a hot gas stream (1400 °F to 2000 °F), which promotes the conversion of NOx to nitrogen and water given sufficient residence time. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NOx conversion mechanism.

*XONON™*: This is an emerging technology that partially burns fuel in a low-temperature pre-combustor and completes combustion in a catalytic combustor. The result is partial combustion with a lower temperature (and less NOx formation) followed by flameless catalytic combustion to further inhibit NOx formation. This technology has been demonstrated, but the design will be unique for each manufacturer and model of gas turbine. It is anticipated that control efficiencies may approach 98%.




Applicant's NOx BACT Proposal

*Regarding selection of technology*: In addition to the DLN combustion technology for the specified gas turbine, the applicant identified the following add-on control technologies for reducing NOx emissions: wet injection, SCR, SCONOx™, XONON™, NOxOUT™, Thermal DeNOx ™, and nonselective catalytic reduction (NSCR). Of these technologies, the applicant indicates that only DLN, wet injection, SCR, SCONOx™, and XONON™ are feasible for this project. The applicant does not believe that XONON™ nor SCONOx™ has been demonstrated for a "F-class" gas turbine. The applicant did review SCONOx™ as the top control technology, followed by SCR. These add-on controls would be in addition to DLN combustion for gas firing and wet injection for oil firing. The applicant noted the following adverse impacts with regard to SCONOx™.

- *Energy Impacts*: The pressure drop across the SCONOx™ system causes backpressure on the gas turbine, which can reduce power output. SCONOx™ also requires the use of natural gas and steam to regenerate the catalyst. The overall energy requirement is approximately equivalent to 35,600,000 kilowatt-hours (kWh) per year for each unit. The combined energy requirements in terms of natural gas usage would be 358 million cubic feet of natural gas per year, which is roughly 2.24% of the gas turbine heat input. The applicant believes that the energy impacts of SCONOx™ are approximately 6 times greater than those caused by SCR.
- *Environmental Impacts*: Because of the backpressure and energy requirements noted above, the applicant estimates that a SCONOx™ system would increase criteria pollutants for each gas turbine by 41 tons per year (and carbon dioxide emissions by 23,000 tons per year) over the levels attributable to a SCR system. The applicant does concede that ammonia is not used or emitted from the SCONOx™ system.
- *Economic Impacts*: The applicant estimates that the installation of SCONOx™ to achieve a NOx standard of 3.5 ppmvd corrected to 15% oxygen for gas firing would result in estimated annualized costs of about $5,674,000 per year and an overall cost effectiveness of $8,597 per ton of NOx removed. This compares to the applicant's estimated cost effectiveness of $2,741 per tons of NOx removed for an SCR system at 3.5 ppmvd corrected to 15% oxygen.

The applicant rejects SCONOx™ based on the significant energy, environmental, and economic impacts. SCONOx™ and SCR are capable of achieving nearly the same level of NOx reduction. Although SCONOx™ achieves this level without additional emissions of ammonia, SCR systems can be designed and operated to minimize ammonia slip. The use of distillate oil for this project further complicates the SCONOx™ system and can cause premature fouling through introduction of sulfur compounds. (It is possible that a SCOSOx™ catalyst could be added upstream to reduce $SO_2$ emissions.) The applicant believes that the energy and environmental disadvantages of a SCONOx™ system outweigh the any potential additional reductions in NOx. The applicant therefore requests a BACT determination of SCR with DLN for gas firing and wet injection for oil firing.

*Regarding Selection of NOx Emission Rate*: Following selection of SCR as the appropriate add-on control technology, the applicant addressed designing and operating the SCR to achieve 3.5 ppmvd versus 2.5 ppmvd, both corrected to 15% oxygen.

In addition to noting several issues in demonstrating compliance with an emission rate as low as 2.5 ppmvd corrected to 15% oxygen, the applicant presented energy, environmental, and economic impacts associated with the lower limit. The applicant estimates that achieving the lower emission rate of 2.5 ppmvd corrected to 15% oxygen would result in the following detrimental effects relative to achieving 3.5 ppmvd corrected to 15% oxygen:

- Backpressure increase of 4%;
- Energy loss of 206,222 kWh/year per turbine;
- 0.3 tons of additional criteria pollutants per year per turbine;
- 131 tons per year per turbine of additional carbon dioxide emissions; and
- $3,463 per ton of additional NOx removed (incremental cost effectiveness).

The applicant rejected the lower emission rate because of the increased difficulty in demonstrating compliance and the negative energy, environmental, and economic impacts. The applicant requests the following NOx standards as BACT.

a. Oil Firing  12 ppmvd corrected to 15% oxygen, 24-hour average

b. Gas Firing: 3.5 ppmvd corrected to 15% oxygen, 24-hour average

*{Note: The requested gas firing limit represents approximately a 86% reduction from DLN combustion (25 ppmvd corrected to 15% oxygen).}*

<u>Department's Draft BACT Determination</u>

The Department also ranks SCONOx™ and SCR as the top add-on control technologies for combined cycle operation. SCONOx™ has been demonstrated on small units in California and has been purchased for a small source in Massachusetts. California regulators and have permitted the La Paloma Plant near Bakersfield for the installation of one 250 MW block with SCONOx™. The overall project includes several more 250 MW blocks with SCR for control. According to industry sources, the installation has proceeded with a standard SCR due to schedule constraints. Recently, PG&E Generating has been approved to install SCONOx™ on two "F-class" units at Otay Mesa, approximately 15 miles southeast of San Diego, California. Additionally, EPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with a SCONOx™ system. SCONOx™ has not been applied on any major sources in ozone attainment areas, apparently due to cost considerations. The Department is interested in seeing this ammonia-free emissions technology demonstrated on a large "F-class" unit. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The pressure drop across the SCONOx™ system may be greater than that of SCR.
- The energy losses described for SCONOx™ relative to SCR are relatively small and would occur on a day-to-day basis. The additional negative impacts associated with SCR at 2.5 versus SCR at 3.5 ppmvd corrected to 15% oxygen are even smaller. The applicant's estimates of energy and environmental impacts assume that energy would be needed to replace the backpressure loss each and every day, 24 hours a day.
- The Department does not endorse the applicant's estimate of the cost effectiveness for either SCONOx™ or SCR. It is unlikely, however, that SCONOx™ would be cost effective for this project.
- The Department notes that the applicant presented a cost effectiveness value of $2,741 per ton of NOx removed for the 3.5 ppmvd corrected to 15% oxygen option, compared to just $2,770 per ton of NOx removed under the 2.5 ppmvd corrected to 15% oxygen option. The difference between the two estimated annual costs is less than 5 percent. Although the incremental cost is over $3,000 per ton, the lower NOx emission rate cannot be ruled out on grounds of cost effectiveness.

The Department rejects SCONOx™ primarily as not being cost effective and accepts conventional SCR as the BACT. The Department establishes the following draft BACT standards.

a. Oil Firing: 10 ppmvd corrected to 15% oxygen, 24-hour average

b. Gas Firing: 2.5 ppmvd corrected to 15% oxygen, 24-hour average

The above limit is much more stringent than the NSPS Subpart GG standard for gas turbines. Oil firing will be subject to the same conditions as Power Block 2, namely an aggregated fuel consumption limit equivalent to 720 hours of operation for each unit. The oil firing limit is consistent with the determinations of the Department and other states.

Compliance with the standards will be demonstrated by CEMS. The Department set the averaging time for the NOx emission standard at a 24-hour block starting at midnight of each day. This averaging time simplifies compliance recordkeeping requirements, provides for sufficient averaging time to account for measurement uncertainties, and is appropriate given that the ambient $NO_2$ standard is based on an annual average.

These determinations are consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. In at least seven previous BACT determinations issued since August 2001, the Department specified a NOx BACT of 2.5 ppmvd corrected to 15% oxygen for "F-class" combined cycle gas turbines with conventional SCR. The Department also notes that other similar combined cycle projects in Maine and Washington received BACT limits of 2.0 ppmvd corrected to 15% oxygen for gas firing with SCR. The Department's proposed BACT limit considers measurement uncertainties associated with very low emission rates and the proposed ammonia slip limit of 5 ppmvd corrected to 15% oxygen. EPA Region 4 has commented that 2.5 ppmvd corrected to 15% oxygen represents the lowest BACT level in the region and that the 24-hour averaging period is acceptable in light of the low standard.

## 6. DRAFT BACT STANDARDS – CARBON MONOXIDE

Discussion of CO Emissions

Gas turbines emit CO because of incomplete combustion of the fuels. For many combustion processes, CO emissions are inversely proportional to NOx emissions. The DLN combustor design for modern "F-class" gas turbines, however, has successfully reduced CO emissions concurrently with lowered NOx emissions.

Applicant's CO BACT Proposal

The applicant identified two control options that are technically feasible and commercially available for gas turbines: (1) an efficient combustion design with good operating practices, and (2) a catalytic oxidation system designed to achieve a 2.5 ppmvd emission rate.

After attaining lean premix steady-state operation, the DLN combustion design proposed for this project results in low emissions of CO while also maintaining low NOx emissions. The automated gas turbine control system monitors and controls the gas turbine combustion process and operating parameters, such as the air/fuel distribution and staging, turbine speed, load conditions, temperatures, and heat input. No adverse energy, environmental, or economic impacts were identified with the use of an efficient combustion design and good operating practices. ("Good operating practices" means operating the unit in accordance with the manufacture's recommendations for efficient combustion, properly maintaining the gas turbine, and appropriate tuning of the combustor and control system.)

A catalytic oxidation system consists of a noble metal catalyst section incorporated into the gas turbine exhaust. The catalyst promotes greater oxidation of CO (to carbon dioxide) at much lower temperatures (650 °F to 1150 °F) than would occur without a catalyst. Control efficiencies are primarily a function of the gas residence time, catalyst activity, and uncontrolled emission levels. Control efficiencies can approach more than 90% given a sufficient inlet concentration. The applicant identifies two alternatives for installing an oxidation catalyst. The first consists of an oxidation catalyst system prior to the HRSG to reduce CO emissions from the turbine. The second alternative is installing the catalyst system (or SCONOx™) within the HRSG. Capital costs and technical feasibility are not affected by placement relative to the HRSG.

The applicant recognized a catalytic oxidation system as the top control for CO emissions, but identified the following additional adverse impacts.

*Energy Impacts*: Installation of a catalytic oxidation system results in a pressure drop across the catalyst bed of approximately 1.5 to 2 inches of water gauge. This pressure drop causes backpressure on the gas turbine and reduces the power output from the unit resulting in an estimated energy penalty of approximately 3 million kWh/year. The applicant estimates the lost power generation to be approximately equivalent 32 million cubic feet of natural gas per year to replace the lost energy. Energy impacts are further exasperated when considering SCONOx™, which the applicant estimates would require the replacement of 35.8 MMBtu per year (358 million cubic feet of natural gas).

*Environmental Impacts*: The applicant contends that the maximum CO impacts are less than 0.1% of the applicable NAAQS and that no significant environmental benefit is realized by the installation of a catalytic oxidation system. The applicant states that making up the energy lost to the back pressure caused by an oxidation catalyst would result in 2,030 tons per year of additional carbon dioxide.

*Economic Impacts*: The applicant estimates that the installation of a catalytic oxidation system would result in total capital investment of approximately $1.64 million for one gas turbine with a total annualized cost of approximately $700,340 per year per gas turbine. Assuming 90% control efficiency, the catalytic oxidation system would remove in an additional 186 tons of CO per year per gas turbine resulting in a cost effectiveness of approximately $3,773 per ton of CO removed.

The applicant rejected the catalytic oxidation system as not cost effective for the project. In addition, the applicant did not believe the additional controls would provide any measurable reductions in air quality impacts. The applicant proposed the following CO emissions standards for project based on the efficient combustion, the firing of natural gas as the primary fuel, and good operating practices.

a. Oil Firing: 30 ppmvd corrected to 15% oxygen

b. Gas Firing: 16 ppmvd corrected to 15% oxygen

The applicant agreed that compliance is most appropriately determined by a CO CEMS on a 24-hour block average.

<u>Department's Draft CO BACT Determinations</u>

The Department also recognizes the catalytic oxidation system as the top control alternative for CO emissions. The Department offers the following comments regarding the applicant's discussion of the additional adverse impacts.

- The Department agrees that installation of a catalytic oxidation system would result in a small energy penalty due to the pressure drop across the catalyst.
- The Department rejects the applicant's argument that the further reduction of CO emissions would have negligible ambient impacts. The PSD preconstruction review process is specifically established for areas that are meeting the NAAQS in order to prevent the deterioration of the current air quality. Actual ambient impacts from the project are evaluated in the modeling analysis and are not considered in making the BACT determination.
- A catalytic oxidation system would also reduce emissions of VOC.
- The Department does not endorse the applicant's estimate of the cost effectiveness of $3,770 per ton of CO removed for a catalytic oxidation system. Recent similar projects (for example, CPV Gulfcoast) have obtained vendor equipment cost quotes that are approximately 25% less. However, the estimate appears to be within the high end of the range of such estimates for other similar projects ($1,500 to $4,500 per ton).

Recent tests for the same model gas turbine (Siemens Westinghouse 501FD) indicate actual CO emission levels significantly below the performance guaranteed by the manufacturer. Eight tests on 6 turbines operating at full load in Alabama and Pennsylvania show CO emissions averaging 1.1 ppmvd corrected to 15% oxygen. When operating at 85% load, average emissions in 2 tests were below 3 ppmvd corrected to 15% oxygen. Even at low load operation, available stack tests suggest that actual CO performance at levels below manufacturer guarantees is possible and attainable. The following tables summarize recent stack tests.

**Table 6-1. Siemens Westinghouse 501FD Performance Test Summary (Base Load)**

| Plant | Unit | State | Test Date | Load | CO (ppmvd at 15% oxygen) | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Run 1 | Run 2 | Run 3 | Avg |
| Calpine - Decatur | 1 | AL | 06/05/02 | Base (100%) | 0.35 | 0.34 | 0.17 | 0.29 |
| Calpine - Decatur | 2 | AL | 06/04/02 | Base (100%) | 0.26 | 0.43 | 0.43 | 0.37 |
| Calpine - Decatur | 1 | AL | 10/10/02 | Base (100%) | 1.73 | 1.07 | 1.87 | 1.56 |
| Calpine - Decatur | 2 | AL | 10/09/02 | Base (100%) | 1.31 | 1.37 | 1.48 | 1.39 |
| AEC - McWilliams | 1 | AL | 12/22/01 | Base (100%) | 2.06 | 2.31 | 2.47 | 2.28 |
| AEC - McWilliams | 2 | AL | 12/23/01 | Base (100%) | 2.47 | 1.99 | 1.95 | 2.14 |
| Calpine - Ontelaunee | 1 | PA | 08/13/02 | Base (100%) | <0.41 | <0.42 | <0.42 | <0.42 |
| Calpine - Ontelaunee | 2 | PA | 08/14/02 | Base (100%) | <0.42 | <0.42 | <0.42 | <0.42 |

**Table 6-2. Siemens Westinghouse 501FD Performance Test Summary (Reduced Loads)**

| Plant | Unit | State | Test Date | Load | CO (ppmvd at 15% oxygen) | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Run 1 | Run 2 | Run 3 | Avg |
| AEC - McWilliams | 1 | AL | 12/22/01 | 85% | 2.75 | 2.86 | 2.74 | 2.78 |
| AEC - McWilliams | 2 | AL | 12/23/01 | 85% | 2.26 | 2.48 | 2.67 | 2.47 |
| AEC - McWilliams | 1 | AL | 12/22/01 | 70% | 16.81 | 17.08 | 17.33 | 17.1 |
| AEC - McWilliams | 2 | AL | 12/23/01 | 70% | 12.59 | 12.73 | 13.45 | 12.9 |
| Calpine - Decatur | 1 | AL | 06/05/02 | 60% | 1.27 | 0.81 | 0.54 | 0.87 |
| Calpine - Decatur | 2 | AL | 06/04/02 | 60% | 13.04 | 8.04 | 6.55 | 9.21 |

As shown by specific test data, CO emissions are much lower than recent permit limits and manufacturer's guarantees. Such low actual CO emissions would tend to drive the cost effectiveness of a catalytic oxidation system even higher. The Department determines that add-on controls to further reduce CO emissions are unwarranted given the low emissions characteristics of this particular gas turbine and the firing of natural gas as the primary fuel. Therefore, a catalytic oxidation system is rejected as not cost effective for this specific project.

Recognizing that the turbines will probably perform better than guaranteed by the manufacturer, the Department will require only that the HRSGs be designed to accommodate the future addition of an oxidation catalyst, should the turbine prove incapable of meeting the specified CO emission limit. If the turbine is not meeting the emission limit, then the addition of an oxidation catalyst would appear to be cost effective – especially since incorporating this possibility into the HRSG design should reduce the retrofit costs.

The Department establishes the following draft BACT standards.

a. Oil Firing: 20 ppmvd corrected to 15% oxygen, 24-hour block average

b. Gas Firing: 10 ppmvd corrected to 15% oxygen, 24-hour block average

The "24-hour block average" is defined as the daily average for the actual hours operated in that mode. For example, assume the unit operates 20 hours of normal operation with natural gas firing and 4 hours with oil firing. Then, two separate compliance determinations would be made for the day: one for normal gas firing based on an average of 20 hourly values and one for oil firing based on an average of 4 hourly values. This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the CO standard will be demonstrated by CEMS. Continuous monitoring has been standard practice for recent Department determinations for combined cycle gas turbine projects.

## 7. DRAFT BACT STANDARDS – VOLATILE ORGANIC COMPOUNDS

Discussion

VOC emissions result from incomplete combustion when firing natural gas and distillate oil. Large combustion turbines offer high temperatures with efficient combustion resulting in relatively low levels of VOC. For this project, VOC emissions from one gas turbine are expected to be less than 30 tons per year. Similar to the control of CO, catalytic oxidation systems are available for reducing VOC emissions from gas turbines. Although one oxidation catalyst vendor noted that typical VOC removal in a turbine application is 30% to 40%, catalytic oxidation systems can achieve emissions reductions approaching 90% depending on the uncontrolled inlet VOC emission rate. The applicant suggested that even at 90% removal, such a system would not be cost effective for the control of CO emissions.

Applicant's Proposal

The applicant proposes the following emissions standards based on efficient combustion of natural gas and distillate oil and good operating practices for the gas turbines.

a. Oil Firing: 10 ppmvd corrected to 15% oxygen

b. Gas Firing: 2.0 ppmvd corrected to 15% oxygen

The applicant proposes to demonstrate compliance with the standards by conducting performance tests in accordance with EPA Methods 18, 25, and 25A.

Department's Draft VOC BACT Determinations

Although the Department does not necessarily endorse the applicant's cost proposal, the Department nevertheless agrees that a catalytic oxidation system is not cost effective for this project. Therefore, the efficient combustion design and good operating practices are determined to represent BACT. The Department establishes the following draft BACT standards.

a. Oil Firing: 10 ppmvd as propane corrected to 15% oxygen

b. Gas Firing: 2.0 ppmvd as propane corrected to 15% oxygen

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance shall be demonstrated by conducting performance tests in accordance with EPA Method 25A. EPA Method 18 may also be simultaneously performed to deduct emissions of methane and ethane. (Methane and ethane are excluded from the definition of "VOC.")

## 8. DRAFT BACT STANDARDS - PARTICULATE MATTER

Discussion – Gas Turbines

Emissions of particulate matter will result from incomplete combustion of natural gas and distillate oil as well as contaminants in these fuels. Particulate matter emissions increase with incomplete fuel combustion as well as with higher concentrations of ash, sulfur, and trace elements in a given fuel. However, natural gas is a clean fuel containing little ash, sulfur, or other contaminants. Similarly, distillate oil contains little of these contaminants and is restricted to the equivalent of only 720 hours per year per gas turbine for this project. (19,703,000 gallons aggregated among the 2 gas turbines, assuming 141.2 MMBtu per 1000 gallons and a firing rate of 1,932 MMBtu/hr.) Attachment A shows typical BACT determinations for particulate matter from large gas turbine projects. Some of the projects include front and back half catch for PM limits; therefore, comparison is not simple. Emissions of particulate matter when injecting ammonia for NOx control may be higher due to the formation of fine particulates such as ammonia sulfates and bisulfates.

Applicant's Proposal – Gas Turbines

At the estimated uncontrolled emission rates when firing natural gas, the applicant states the maximum particulate loading from the project will be less than normal fabric filter specifications. In addition to firing natural gas and very low sulfur distillate oil, the applicant proposes the following visible emissions limit as a work practice standard in lieu of a particulate matter emissions standard.

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

Department's Draft PM BACT Determinations – Gas Turbines

The total potential emissions from a single gas turbine are estimated to be about 60 tons per year. Actual test data indicates that particulate matter emissions may actually be one-tenth of this level. The Department agrees that further control of particulate matter emissions with add-on controls would be cost prohibitive for large gas turbines firing primarily natural gas with restricted amounts of very low sulfur distillate oil. The specification of clean fuels is a pollution prevention technique and is given favorable consideration for this project. Therefore, the following conditions are established as the draft BACT standards.

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

b. The gas turbines shall fire natural gas as the primary fuel. The gas turbines may fire up to 19,703,000 gallons per year distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. Compliance with the fuel specifications shall be determined by records of the fuel analyses. Compliance with the visible emissions standard will be demonstrated by conducting at least annual opacity observations in accordance with EPA Method 9. In addition, the CO CEMS standard will serve a continuous indication of efficient combustion practices to minimize emissions of particulate matter.

## 9. DRAFT BACT STANDARDS – SULFURIC ACID MIST AND SULFUR DIOXIDE

Discussion

Emissions of $SO_2$ are generated from fuel sulfur with small amounts of $SO_2$ being converted to SAM. Natural gas is a clean fuel containing little ash, sulfur, or other contaminants. The distillate oil specified for this project also contains very low sulfur levels.

Applicant's Proposal

The applicant states that flue gas desulfurization systems are not available, technically feasible, demonstrated, nor cost effective for gas turbines. The applicant proposes the use of clean fuels as previously specified to limit emissions of SAM and $SO_2$ from the project.

Department's Draft SAM/$SO_2$ BACT Determinations

The potential emissions from a single gas turbine are estimated to be 70 tons of $SO_2$ per year and 10.5 tons of SAM per year. Given the high flow rates and estimated low emission levels, the Department agrees that installation of add-on flue gas desulfurization equipment is not reasonable. All of the recent gas turbine projects control $SO_2$ and SAM by limiting the sulfur content of the fuel (See Attachment A). The projects ultimately rely on a fairly uniform gas distribution network, which typically provides natural gas with a fuel sulfur content of less than 1 grain per 100 standard cubic feet of gas. Distillate oil will be brought to the plant by truck and the vendor must meet contractual specifications regarding the fuel sulfur content. The Department determines that the following fuel specifications represent BACT for limiting emissions of SAM and $SO_2$ from the project.

a. The gas turbines shall fire natural gas as the primary fuel. The gas turbines may fire up to 19,703,000 gallons per year distillate oil containing no more than 0.05% sulfur by weight as a restricted alternate fuel.

This determination is consistent with recent determinations for combined cycle gas turbine projects in attainment areas. See Attachment A. The above fuel specifications effectively limit potential emissions of SAM and $SO_2$ emissions, is typically considered BACT for similar gas turbine projects, and is clearly more stringent than the

NSPS Subpart GG standard of 0.8% sulfur by weight for gas turbines. Compliance with the fuel specifications shall be determined by records of the fuel analyses.

## 10. DRAFT STANDARDS FOR AMMONIA SLIP EMISSIONS

Ammonia is injected into the exhaust gas stream as part of the SCR system that is used to control NOx emissions. Some of the ammonia will escape past the catalyst without reaction as "ammonia slip" or combine with sulfur to form fine particulate matter such as ammonium sulfates and bisulfates. Elevated levels of ammonia slip may indicate a degrading catalyst. Limiting ammonia slip will also minimize the formation of fine particulate matter formation previously mentioned. Therefore, the following draft ammonia slip standard is specified.

a. The SCR system shall be designed and operated for a maximum ammonia slip level of 5 ppmvd corrected to 15% oxygen.

This determination is consistent with recent Department determinations for combined cycle gas turbine projects in Florida. Compliance with the ammonia slip level shall be demonstrated at least annually in accordance with EPA's Conditional Test Method No. 27. Ammonia has been designated as a hazardous substance under Federal regulations (Emergency Planning and Community Right-to-Know Act, EPCRA, also known as "SARA Title III"). Ammonia must be carefully managed to prevent accidental spills or nitrogen loading of the waters and soils.

## 11. NSPS REQUIREMENTS

Gas Turbines

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

- NOx (gas or oil) $\leq$ 112.5 ppmvd corrected to 15% oxygen (based on a heat rate of ~ 9.6 kilojoules per watt-hour or 9,100 Btu per kilowatt-hour); and
- $SO_2$ emissions are limited by the use of a fuel with a sulfur content of no more than 0.8% by weight.

The Department considers the draft BACT standards more stringent than the NSPS standards. However, the NSPS also has other specific requirements for notification, record keeping, performance testing, and monitoring of operations. The applicant is referred to the latest version of the CFR for these requirements.

## 12. MACT 112(g) APPLICABILITY

EPA is required to promulgate MACT standards for HAP emissions from gas turbines. On January 14, 2003, EPA proposed the combustion turbines NESHAP (68 FR 1888). Because EPA has not yet promulgated these standards, states are required to review new projects for the applicability of Section 112(g) of the Act (see 40 CFR 63.40 - 63.44). If emissions from a new project are 10 tons per year or more of any single HAP or 25 tons per year or more of all combined HAPs, the new project could be subject to a case-by-case MACT determination. The applicant estimated total HAP emissions from the proposed project to be 7.3 tons per year, which would not trigger the 112(g) requirement.

In the memorandum dated August 21, 2001, EPA states that the original HAP emissions information (EPA memorandum dated 12/30/99) was based primarily on existing diffusion flame combustor technology. This technology results in higher emissions of CO, NOx, and HAPs than lean premix combustor designs, such as Siemens Westinghouse's DLN combustion technology. Based on additional emissions performance testing, EPA states that the average formaldehyde emission factor is $6.49 \times 10^{-05}$ lb/MMBtu for large gas turbines (10 MW to 170 MW) utilizing lean premix combustion. Because formaldehyde had the highest emission rate for HAPs, it is reasonable to assume that other HAPs would also be much lower for lean premix combustion.

One theory for the much lower HAP emission levels is that, although the premixing of fuel and air with staged entry limits flame temperature and residence time at peak flame temperatures, it also reduces "cold spots" throughout the combustion zone providing more uniform destruction. EPA also states that, "For purposes of monitoring HAP performance of lean premix combustor turbines, NOx emission levels characteristic of lean premix combustor technology could be used as an indicator of proper lean premix combustor performance, which in turn would assure proper operation and low HAP emissions." The Department believes that the project has potential HAP emissions of less than 10 tons per year for all individual HAPs and less than 25 tons per year for all combined HAPs. Based on all of the available information, a case-by-case 112(g) MACT determination is not required for this project. Each gas turbine will continuously monitor CO and NOx emissions, which will ensure proper lean premix combustor performance and thereby low HAP emissions.

## 13. MACT 112(j) AND 40 CFR PART 63, SUBPART YYYY APPLICABILITY

Section 112(j) of the Act establishes the "MACT hammer" dates – deadlines for EPA to establish MACT standards through promulgation of NESHAP for the various source categories. In the event the applicable NESHAP is not yet finalized by its hammer date, Section 112(j) requires that the permitting authority perform a case-by-case MACT determination for all affected sources located at major sources of HAP emissions. The Section 112(j) rules are located at 40 CFR 63.50 through 63.56.

The combustion turbine NESHAP was only recently proposed (as 40 CFR 63, Subpart YYYY; see 68 FR 1888, January 14, 2003). The rule is scheduled to be promulgated – i.e., published as a final rule in the Federal Register – on August 30, 2003. If the NESHAP is not promulgated by October 30, 2003, then the Section 112(j) rules would require permit applications to initiate case-by-case MACT determinations for combustion turbines located at major sources of HAP emissions. (Note that this applicability analysis assumes EPA's proposed changes to the MACT hammer dates are adopted – see 67 FR 72875, December 9, 2002.)

Based on EPA guidance in the various preambles to the Section 112(j) rules, the applicability provisions in the proposed NESHAP should be used to make the decision regarding what constitutes an affected source for purposes of a case-by-case MACT determination. The proposed combustion turbines NESHAP lists the affected sources as "...any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions." (40 CFR 63.6090(a), proposed) Accordingly, the gas turbines at Power Block 3 would be affected sources – they are combustion turbines located at a major source of HAP emissions.

To comply with this requirement for Power Block 3, the permittee must submit the "Part 1 MACT application" within 30 days of startup. This Part 1 application simply notifies the permitting agency of the existence of the source and the applicability of the 112(j) standards. The Part 2 application, which contains the substantive information needed for the case-by-case MACT determination, can be submitted up to 24 months following the earlier Part 1 application.

Neither application need be submitted for Power Block 3, of course, if Subpart YYYY is promulgated prior to Power Block 3 startup. Subpart YYYY, if promulgated, will apply instead of the Section 112(j) rules. Instead of a case-by-case MACT, the source would comply with the general MACT for combustion turbines. Note that the Power Block 3 turbines will be considered "new stationary sources" for purposes of the MACT because their construction will commence after January 14, 2003. As such, Power Block 3 will have to comply with the emission limitations and operating limitations in Subpart YYYY upon startup.

In summary, if Subpart YYYY is promulgated prior to startup, then Power Block 3 must comply with Subpart YYYY at startup. If Subpart YYYY is not promulgated prior to startup, then the permittee must submit a Part 1 MACT application within 30 days of startup. If Subpart YYYY is still not promulgated 24 months after the Part 1 MACT application is submitted, then the Part 2 MACT application is due.

## 14. DEPARTMENT'S ESTIMATED ANNUAL EMISSIONS

The following table shows the estimated annual emissions from the completed combined cycle unit based on the draft permit conditions.

**Table 14-1. Estimated Annual Emissions**

| Pollutant | Project Emissions (tons per year) |
|---|---|
| CO | 440 |
| Lead | 0.02 |
| NOx | 208 |
| PM | 107 |
| $SO_2$ | 111 |
| SAM | 17 |
| VOC | 170 |

## 15. EXISTING AIR QUALITY IN THE VICINITY OF THE PROJECT

Description of Vicinity

The project will be located on County Road 555 in Bartow, Polk County. The site is several miles east of I-75 and south of I-4 in Polk County.

Refer to Figure 15-1. The immediate area is sparsely populated. St. Petersburg in Pinellas County is about 50 miles west of Hines across Tampa Bay. Tampa is about 35 miles northwest of the Hines Complex. TECO Polk is about 8 miles to the southwest of Hines and Lakeland Electric C.D. McIntosh is located about 20 miles to the north of Hines.

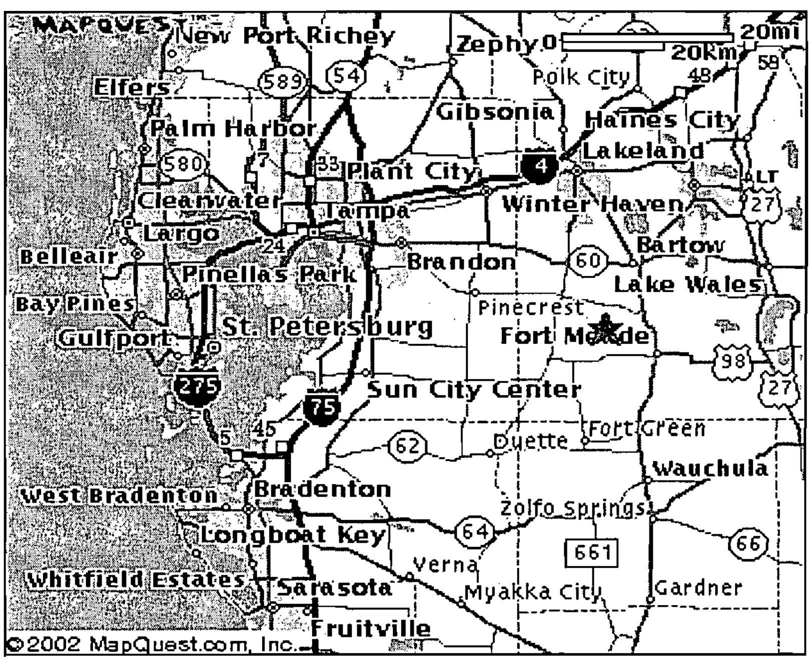



**Figure 15-1. Location of Project, and Nearby Cities**

Climate

The average January temperature for Polk County is 61.1 degrees F and the average August temperature is 81.8 degrees F. The average annual rainfall is 49.21 inches. Winds are predominately out of the East-Northeast.

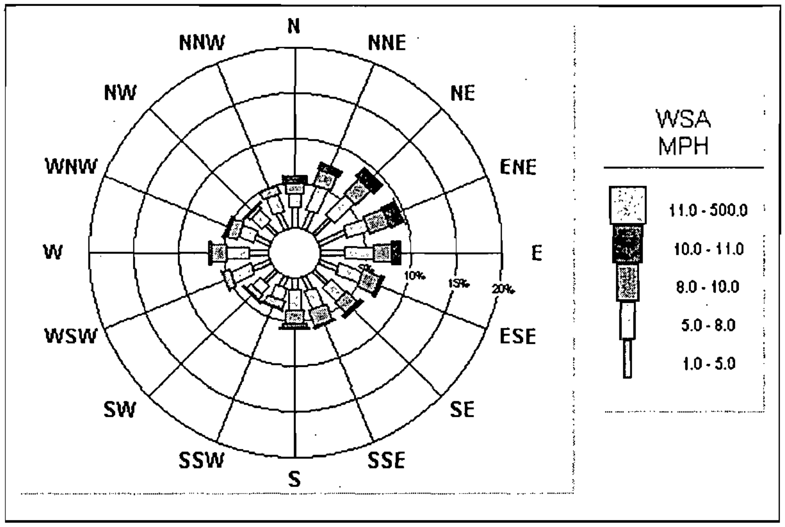



**Figure 15-2. Polk County Wind Rose – January 2001 to December 2001**

Major Stationary Sources in Polk County

The current largest sources of air pollutants (stack emissions) in Polk County are listed below:

**Table 15-1. Major Sources of $SO_2$ in Polk County (2001)**

| Owner/Company | Site Name | Tons per year |
|---|---|---|
| Lakeland Electric | C.D. McIntosh Power Plant | 10,409 |
| IMC Phosphates Company | IMC Phosphates Co (New Wales) | 9,395 |
| Cargill Fertilizer, Inc. | Cargill Fertilizer - Bartow | 4,262 |
| Cargill Fertilizer, Inc. | Green Bay Plant | 3,621 |
| IMC Phosphates Company | IMC Phosphates Co (South Pierce) | 3,467 |
| U.S. Agri-Chemicals Corporation | U.S. Agri-Chemicals – Ft Meade | 2,152 |
| Tampa Electric | Polk Power Station | 863 |
| Lakeland Electric | Charles Larsen Memorial Power Plant | 309 |
| **Florida Power** | **Hines Power Block 3** | **137*** |

* Potential emissions based on application.

**Table 15-2. Major Sources of $NO_X$ in Polk County (2001)**

| Owner/Company | Site Name | Tons per year |
|---|---|---|
| Lakeland Electric | C.D. McIntosh Power Plant | 7,951 |
| Tampa Electric | Polk Power Station | 616 |
| IMC Phosphates Company | IMC Phosphates Co (New Wales) | 404 |
| Florida Power | Hines Energy Complex (existing facility) | 327 |
| Ridge Generating Station | Ridge Generating Station | 304 |
| **Florida Power** | **Hines Power Block 3** | **267*** |
| Calpine | Auburndale Cogeneration Facility | 215 |
| Lakeland Electric | Charles Larsen Memorial Power Plant | 206 |

* Potential emissions based on application.

**Table 15-3. Major Sources of VOC in Polk County (2001)**

| Owner/Company | Site Name | Tons per year |
|---|---|---|
| Citrosuco North America | Citrosuco North America | 1,047 |
| Cargill Citro Pure, L.P. | Cargill Citro Pure, L.P. | 788 |
| Cutrale Citrus Juices USA, Inc. | Cutrale Citrus Juices | 701 |
| Citrus World, Inc. | Citrus World Inc. | 353 |
| Citrus World, Inc. | Florida's Natural Growers- Bartow | 228 |
| Carpenter Co., Insulation Division | Carpenter Co., Insulation Division | 195 |
| Southern Bakeries, Inc. | Butterkrust Bakeries | 105 |
| Lakeland Drum Service, Inc. | Lakeland Drum Service | 82 |
| Holly Hill Fruit Products | Holly Hill Fruit Products | 73 |
| **Florida Power** | **Hines Power Block 3** | **57*** |

* Potential emissions based on application.

**Table 15-4. Major Sources of PM in Polk County (2001)**

| Owner/Company | Site Name | Tons per year |
|---|---|---|
| Lakeland Electric | C.D. McIntosh Power Plant | 394 |
| IMC Phosphates Company | IMC Phosphates Co (New Wales) | 191 |
| **Florida Power** | **Hines Power Block 3** | **121*** |
| Cargill Fertilizer, Inc. | Green Bay Plant | 120 |
| IMC Phosphates Company | IMC Phosphates Co (South Pierce) | 116 |
| Cargill Fertilizer, Inc. | Cargill Fertilizer - Bartow | 42 |

* Potential emissions based on application.

**Table 15-5. Major Sources of CO in Polk County (2001)**

| Owner/Company | Site Name | Tons per year |
|---|---|---|
| Citrosuco North America | Citrosuco North America | 928 |
| Cutrale Citrus Juices USA, Inc. | Cutrale Citrus Juices | 870 |
| **Florida Power** | **Hines Power Block 3** | **744*** |
| Ridge Generating Station | Ridge Generating Station | 732 |
| Lakeland Electric | C.D. McIntosh Power Plant | 443 |
| Cargill Citro Pure, L.P. | Cargill Citro Pure, L.P. | 387 |
| Citrus World, Inc. | Citrus World Inc. | 282 |

* Potential emissions based on application.

Air Quality Monitoring in Polk County

Polk County has 7 monitors at 4 sites measuring PM, ozone, and $SO_2$. The 2001 Polk County monitoring network is shown in Figure 15-3.

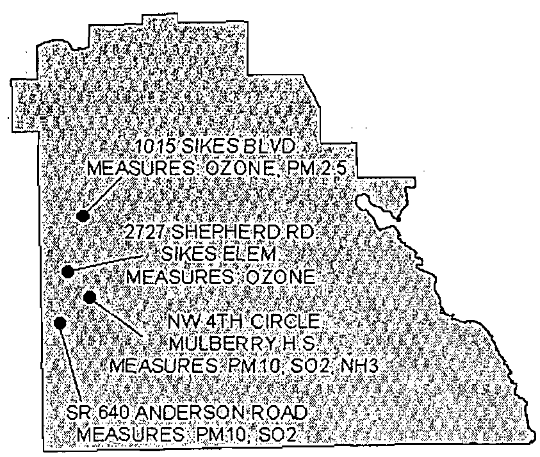



**Figure 15-3. Polk County Monitoring Network**

Ambient Air Quality in Polk County

Measured ambient air quality, along with the National Ambient Air Quality Standards, are given in the following table. Polk County is currently in attainment for all of the criteria pollutants.

**Table 15-6. Existing Air Quality in Polk County**

| Pollutant | Site Location | | Averaging Period | Ambient Concentration | | | | |
|---|---|---|---|---|---|---|---|---|
| | City | Address | | 1st High | 2nd High | Mean | Standard | Units |
| $PM_{10}$ | Mulberry | Anderson and Pinecrest | 24-hour | 165 | 121 | | 150[c] | $ug/m^3$ |
| | | | Annual | | | 25 | 50[b] | $ug/m^3$ |
| | Mulberry | NW 4th Circle | 24-hour | 74 | 59 | | 150[c] | $ug/m^3$ |
| | | | Annual | | | 23 | 50[b] | $ug/m^3$ |
| $SO_2$ | Mulberry | Anderson and Pinecrest | 3-hour | 59 | 48 | | 500[a] | ppb |
| | | | 24-hour | 18 | 17 | | 100[a] | ppb |
| | | | Annual | | | 6 | 20[b] | ppb |
| | Mulberry | NW 4th Circle | 3-hour | 51 | 34 | | 500[a] | ppb |
| | | | 24-hour | 14 | 11 | | 100[a] | ppb |
| | | | Annual | | | 4 | 20[b] | ppb |
| $NO_2$ | Tampa | Simmons County Park | Annual | | | 7 | 53[b] | ppb |
| CO | Plant City | One Raider Place | 1-hour | 5.2 | 2.8 | | 35[a] | ppm |
| | | | 8-hour | 1.6 | 1.6 | | 9[a] | ppm |
| Ozone | Lakeland | 2727 Shepherd Rd | 1-hour | 0.111 | 0.109 | | 0.12[c] | ppm |
| | | | 8-hour | | | | | |
| | Lakeland | 1015 Sikes Blvd | 1-hour | 0.113 | 0.106 | | 0.12[c] | ppm |
| | | | 8-hour | | | | | |
| $PM_{2.5}$ | Polk | 1015 Sikes Blvd | 24-hour | 59 | 35 | | 65[c] | $ug/m^3$ |
| | | | Annual | | | 12 | 15[b] | $ug/m^3$ |

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

## 16. AIR QUALITY IMPACT ANALYSIS

Introduction

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

Significant Impact Analysis

For $PM/PM_{10}$, CO, $NO_X$ and $SO_2$, which have significant impact levels defined for them, a significant impact analysis is performed. In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described in Models and Meteorological Data Used in the Air Quality Analysis, later in this section. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate significant impact levels for the Class I and Class II Areas.

If this modeling at worst load conditions show significant impacts, additional modeling, which includes the emissions from surrounding facilities, or multi-source modeling is required to determine the project's impacts on any applicable AAQS or PSD increments. If no significant impacts are shown, the applicant is exempted from doing any further modeling.

The applicant's initial PM/$PM_{10}$, CO, $NO_X$, and $SO_2$ air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels." These values are tabulated below and compared with the National Ambient Air Quality Standards.

**Table 16-1. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project for Comparison to the PSD Class II Significant Impact Levels**

| Pollutant | Averaging Time | Max Predicted Impact ($ug/m^3$) | Significant Impact Level ($ug/m^3$) | Ambient Air Standards ($ug/m^3$) | Significant Impact? |
|---|---|---|---|---|---|
| $SO_2$ | Annual | 0.04 | 1 | 60 | NO |
| | 24-Hour | 4 | 5 | 260 | NO |
| | 3-Hour | 17 | 25 | 1300 | NO |
| $PM_{10}$ | Annual | 0.04 | 1 | 50 | NO |
| | 24-Hour | 2.5 | 5 | 150 | NO |
| CO | 8-Hour | 26 | 500 | 10,000 | NO |
| | 1-Hour | 80 | 2000 | 40,000 | NO |
| $NO_2$ | Annual | 0.09 | 1 | 100 | NO |

It is obvious that maximum predicted impacts from the project are much less than the respective ambient air quality standards. They are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

The nearest PSD Class I area is the Chassahowitzka National Wilderness Area (CNWA) located about 118 km to the north. The applicant's initial PM/$PM_{10}$, $NO_X$, and $SO_2$ air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable "significant impact levels" for the Class I area. These values are tabulated below. Note that the values are miniscule if compared with the ambient air quality standards given in the previous table. Since these impacts are less than the respective significant impact levels, no further detailed modeling efforts are required in this Class I area.

**Table 16-2. Maximum Project Air Quality Impacts from the Hines Power Block 3 Project Compared with PSD Class I Significant Impact Levels (Chassahowitzka)**

| Pollutant | Averaging Time | Max. Predicted Impact at Class I Area ($ug/m^3$) | Class I Significant Impact Level ($ug/m^3$) | Significant Impact? |
|---|---|---|---|---|
| $PM_{10}$ | Annual | 0.001 | 0.2 | NO |
| | 24-hour | 0.11 | 0.3 | NO |
| $NO_2$ | Annual | 0.001 | 0.1 | NO |
| $SO_2$ | Annual | 0.001 | 0.1 | NO |
| | 24-hour | 0.15 | 0.2 | NO |
| | 3-hour | 0.4 | 1 | NO |

Preconstruction Ambient Monitoring Requirements

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

**Table 16-3. Maximum Project Air Quality Impacts for Comparison to the *de minimis* Ambient Impact Levels**

| Pollutant | Averaging Time | Max Predicted Impact ($ug/m^3$) | De Minimis Level ($ug/m^3$) | Baseline Concentrations ($ug/m^3$) | Impact Greater Than De Minimis? |
|---|---|---|---|---|---|
| $PM_{10}$ | 24-hour | 2.5 | 10 | ~ 100 | NO |
| $NO_2$ | Annual | 0.1 | 14 | ~ 15 | NO |
| $SO_2$ | 24-hour | 4 | 13 | ~ 40 | NO |
| CO | 8-hour | 26 | 575 | ~ 2000 | NO |

There are no ambient standards or *de minimus* air quality levels associated with VOC. However, the pollutant associated with VOC is actually ozone. Projects exhibiting VOC emissions greater than 100 tons per year (TPY) are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The proposed Power Block 3 project VOC emissions are predicted to be no more than 57 TPY, therefore an analysis, including ambient monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses (inclusive of all sources in the area) required by the PSD regulations for this project is an analysis of impacts on soils, vegetation, visibility, and of growth-related air quality modeling impacts.

Models and Meteorological Data Used in the Air Quality Analysis

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

Meteorological data used in the ISCST3 model consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the Tampa International Airport and Ruskin respectively (surface and upper air data). The 5-year period of meteorological data was from 1991 through 1995. This airport station was selected for use in the study because it is the closest primary weather station to the study area and is most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

In reviewing this permit application, the Department has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification 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.

*PSD Class I Area*. The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWA. Meteorological data used in this model was 1990 ISCST3 data, which was enhanced for CALPUFF. Meteorological surface data used were from Gainesville, Tampa, Daytona Beach, Vero Beach, Fort Myers and Orlando. Meteorological upper air data used were from Ruskin, Apalachicola and West Palm Beach. Hourly precipitation data were obtained from 27 stations around the central part of the state.

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

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

<u>Additional Impacts Analysis</u>

*Impact On Soils, Vegetation, And Wildlife*. Very low emissions are expected from this natural gas-fired, with backup fuel oil, combustion turbine in comparison with conventional power plants generating equal power. Emissions of acid rain and ozone precursors will be very low. The maximum ground-level concentrations predicted to occur for $PM_{10}$, CO, $NO_X$ and $SO_2$ 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 also less than the significant impact levels for $PM_{10}$, CO, $NO_X$, and $SO_2$, which 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.

Effects from sulfuric acid mist are also expected to be minor due to the low emissions expected from the Hines Energy Complex Power Block 3. The combination of low $NO_X$ and VOC emissions insures that the project will not contribute significantly to regional ozone levels or to any impacts caused by such ozone levels.

According to the application, native Floridian species of vegetation, such as cypress, slash pine, live oak, and mangrove, will not be visibly damaged when exposed to 1300 ug/m$^3$ of $SO_2$ for 8 hours. This proposed project is expected to emit 17 ug/m$^3$ of $SO_2$ over a 3-hour period and 4 ug/m$^3$ of $SO_2$ over a 24-hour period.

*Impact On Visibility.* Pipeline natural gas is a clean fuel and produces little particulate emissions. The backup fuel oil will be limited to 0.05 percent sulfur and will exhibit relatively low particulate emissions. The very low $NO_X$, $SO_2$, and ammonia emissions will also minimize plume opacity and any effects on regional visibility.

The Class I Chassahowitzka NWA, where visibility impacts are normally of greater concern, is nearly 118 kilometers from the proposed site. Therefore impacts on visibility are expected to be insignificant.

*Growth-Related Air Quality Impacts.* According to the applicant, the project will require about 12 additional permanent employees, some of who will be drawn from the local labor force. Therefore, residential growth due to this project will be minimal.

The applicant also states that the existing transportation infrastructure is adequate for any additional vehicles that may be needed during construction of Power Block 3.

This project is a response to statewide and regional growth and also accommodates more growth. There are no adequate procedures under the PSD rules to fully assess these impacts. However, the type of project proposed has a small overall physical "footprint." After construction of the proposed project, Polk County is expected to remain below the National Ambient Air Quality Standards.

*Hazardous Air Pollutants.* The project is not a major source of hazardous air pollutants (HAPs) and is not subject to any maximum achievable control technology (MACT) requirements pursuant to Department rules or Section 112 of the Clean Air Act.

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.

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.

In making this preliminary determination, the Department also drafted a determination of Best Available Control Technology that may be modified based on comments from the applicant, agencies, and the public.

## 17. DISCUSSION OF COMMERCIAL, RESIDENTIAL, AND INDUSTRIAL GROWTH SINCE 1977

The applicant submitted a report satisfying the requirements of Rule 62-212.400(3)(h)5., F.A.C., which states that a PSD application must include information relating to the air quality impacts of, and the nature and extent of, all general, residential, commercial, industrial, and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. The general conclusion of the growth report is that air quality has been meeting and will continue to meet the ambient standards even considering the impact of not only this project but also the growth that has occurred in Polk County since 1977.

Residential and Commercial Growth

Polk County population has increased 73 percent since 1977, with 204,000 more persons living in the county. There has been a corresponding increase of 68,000 households over the same time period, an increase of 58 percent.

Commercially, 524 establishments and 21,000 employees have been added to the retail sector, and another 413 businesses employing 4,600 persons have been introduced to the wholesale sector. The U.S. Department of Labor classifies Polk County as a "labor surplus area," meaning there are more unskilled laborers than jobs. The labor force as a whole has increased by 88,600 persons, or 85 percent, since 1977.

The tourism industry in Polk County has decreased somewhat, as evidenced by a 25 percent reduction in the number of hotels and motels in the county. At the same time, however, transportation rates have increased, most notably in the automotive sector. With the impact of three major interstates in the county, and given the county's proximity to many major metropolitan areas, there were 51 million more vehicle miles traveled in the county in 2001 compared to 1977 (a 62 percent increase).

Industrial Growth

The growth of the utility industry in Polk County has been considerable since 1977, when net electrical generation was around 400 MW. Currently, the county has nine power plants with a combined output of 2300 MW (an increase of 475 percent). An additional seven power plants are permitted or under construction, which will add another 2,200 MW to bring the total to 4,500 MW (an increase of over 1000 percent). Note that the 4,500 MW total does not include this current project.

The citrus industry in Polk County peaked in the late 1980s and early 1990s, but has seen a net decrease in production since 1977 (by approximately 22 percent). Phosphate mining has also decreased considerably since 1977, falling some 36 percent. Manufacturing has increased slightly, by around 5 percent.

Air Quality Impacts and Trends

Emissions of air pollutants from mobile sources has seen significant decreases since 1977. CO has fallen by 80 percent, VOC has decreased 80 percent, and NO emissions are 56 percent lower.

Ambient monitoring data detail $SO_2$ and $PM_{10}$ or total suspended particulate (TSP) concentrations since 1977. Ozone concentrations have been monitored since 1992. $SO_2$ concentrations have historically been well below the NAAQS. TSP, when it was monitored (1977 - 1987), occasionally exceeded the ambient standards, but since the standard was revised to monitor $PM_{10}$ in 1988, the air quality has been below the NAAQS. Ozone has been below both the 1-hour and the 8-hour ambient standards since it has been monitored.

Conclusions

- Growth since 1977 has not adversely impacted the attainment of the NAAQS for $SO_2$, $PM_{10}$, or ozone.
- The increase in vehicle miles traveled in the county has been offset by decreases in pollution per vehicle, yielding a significant net decrease in emissions from mobile sources.
- The mining and citrus industries have slowed down considerably from 1977 levels.
- Manufacturing and commercial growth has increased along with population growth.
- Growth in the electric utility industry has far exceeded the corresponding growth in the residential, commercial, and other industrial sectors of Polk County.

## 18. PRELIMINARY DETERMINATION

The Department makes a preliminary determination that the proposed project will comply with all applicable state and Federal air pollution regulations as conditioned by the Draft Permit. This determination is based on a technical review of the complete PSD application, reasonable assurances provided by the applicant, the draft BACT determinations, review of the air quality impact analysis, and the conditions specified in the draft permit. Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. Greg DeAngelo is the project engineer responsible for reviewing the application, recommending the BACT determinations, and drafting the permit. Additional details of this analysis may be obtained by contacting the project engineer at (850)921-9506 or the Department's Bureau of Air Regulation at Mail Station #5505, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

## ATTACHMENT A

### Table A-1. Recent NOx Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast

| Project Location | Capacity (MW) | NOx Limit – Fuel Type (ppmvd @ 15% $O_2$) | Technology | Comments |
|---|---|---|---|---|
| **FPC Hines III, FL** | **530** | **2.5 – NG<br>10 – FO** | **SCR<br>WI** | **2x170 MW WH501F (Draft)<br>Equivalent of 720 hours oil / turbine** |
| FPL Martin, FL | 1150 | 2.5 – NG<br>10.0 – FO | SCR<br>WI | 4x170 MW GE 7FA CT (Draft) |
| El Paso Manatee, FL | 250 | 2.5 – NG | SCR | 175 MW GE 7FA |
| El Paso Deerfield, FL | 250 | 2.5 – NG | SCR | 175 MW GE 7FA (Draft 8/2001) |
| CPV Pierce, FL | 245 | 2.5 – NG<br>10 – FO | SCR | 170 MW GE 7FA CT (7/2001) |
| Metcalf Energy, CA | 600 | 2.5 – NG | SCR | 2x170 MW WH501F & Duct Burners |
| Enron/Ft. Pierce, FL | ~250 | 3.5 – NG<br>10 - FO | SCR | 170 MW MHI501F CT Repowering |
| CPV Atlantic, FL | 245 | 3.5 – NG<br>10 – FO | SCR | 170 MW GE 7FA CT |
| CPV Gulfcoast, FL | 245 | 3.5 – NG<br>10 – FO | SCR | 170 MW GE 7FA CT |
| TECO Bayside, FL | 1750 | 3.5 – NG<br>12 - FO | SCR | 7x170 MW GE 7FA CTs, Repowering |
| FPC Hines II, FL | 530 | 3.5 - NG<br>12 - FO | SCR | 2x170 MW WH501F<br>Equivalent of 720 hours oil / turbine |
| Calpine Osprey, FL | 527 | 3.5 – NG | SCR | 2x170 MW WH501F Draft 5/00 |
| Calpine Blue Heron, FL | 1080 | 3.5 – NG | SCR | 4x170 MW WH501F Draft 2/00 |
| Mobile Energy, AL | ~250 | ~3.5 - NG<br>~11 – FO | SCR | 178 MW GE 7FA CT 1/99 |
| Alabama Power Barry | 800 | 3.5 - NG | SCR | 3x170 MW GE 7FA CTs 11/98 |
| Alabama Power Theo | 210 | 3.5 – NG | SCR | 4x170 MW GE 7FA CTs 11/98 |
| KUA Cane Island 3, FL | 250 | 3.5 – NG<br>15 - FO | SCR | 170 MW GE 7FA. 11/99 |

*Notes:*

| | | | |
|---|---|---|---|
| CON = Continuous | DLN = Dry Low $NO_X$ Combustion | FO = Fuel Oil | GE = General Electric |
| SC = Simple Cycle | SCR = Selective Catalytic Reduction | NG = Natural Gas | WH = Westinghouse |
| INT = Intermittent | HSCR = Hot SCR | WI = Water or Steam Injection | ABB = Asea Brown Bovari |
| DB = Duct Burner | CT = Combustion Turbine | | |

**Table A-2. Other Recent Standards for "F-Class" Combined Cycle Gas Turbine Projects in the Southeast**

| Project Location | CO - ppmvd (or lb/MMBtu) | VOC - ppmv (or lb/MMBtu) | PM - lb/MMBtu (or gr/dscf or lb/hr) | Technology and Comments |
|---|---|---|---|---|
| **FPC Hines III, FL** | **10 – NG (24-hr CEMS)<br>20 – FO (24-hr CEMS)** | **2 – NG<br>10 – FO** | **10% Opacity – NG<br>5 ammonia – NG/FO** | **Clean Fuels<br>Good Combustion** |
| FPL Martin, FL | 10.0 – NG<br>15.0 – FO | 1.3 – NG<br>2.5 – FO | 10% Opacity | Clean Fuels<br>Good Combustion |
| El Paso Manatee, FL | 9 (7.4 @15% $O_2$)<br>15 (12 @15% $O_2$) (PA) | 1.4 - NG | 20 lb/hr – (Front & Back)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| El Paso Deerfield, FL | 9 (7.4 @15% O2)<br>15 (12 @15% O2) (PA) | 1.4 - NG | 20 lb/hr – (Front & Back)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| CPV Pierce, FL | 9 - NG (50 - 100% load)<br>15 - NG (PA)<br>20 – FO | 1.4 – NG<br>3.5 FO | 11 lb/hr – NG (front)<br>36 lb/hr – FO (front)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| Metcalf Energy, CA | 6 - NG (100% load) | 0.00126 lb/MMBtu | 12 lb/hr – NG (w DB)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| Enron Ft. Pierce, FL | 3.5 - NG<br>10 - Low Load<br>8 - FO | 2.2 - NG<br>16 – Low Load<br>10 - FO | 10% Opacity | Oxidation Catalyst<br>Clean Fuels<br>Good Combustion |
| CPV Atlantic, FL | 9 - NG (50 - 100% load)<br>15 - NG (PA)<br>20 – FO | 1.4 – NG<br>3.5 FO | 11 lb/hr – NG (front)<br>36 lb/hr – FO (front)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| CPV Gulfcoast, FL | 9 - NG (50 - 100% load)<br>15 - NG (PA)<br>20 – FO | 1.4 – NG<br>3.5 FO | 11 lb/hr – NG (front)<br>36 lb/hr – FO (front)<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| TECO Bayside, FL | 9 – NG (24-hr CEMS)<br>20 – FO (24-hr CEMS) | 1.3 – NG<br>3 - FO | 12 lb/hr – NG<br>30 lb/hr - FO | Clean Fuels<br>Good Combustion |
| FPC Hines II, FL | 16 - NG (24-hr CEMS)<br>30 – FO (24-hr CEMS) | 2 – NG<br>10 – FO | 10% Opacity – NG<br>5/9 ammonia – NG/FO | Clean Fuels<br>Good Combustion |
| Calpine Osprey, FL | 10 – NG<br>17 – NG (DB&PA) | 2.3 – NG<br>4.6 – NG (DB&PA) | 24 lb/hr – NG (DB&PA)<br>10 percent Opacity<br>9 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| Calpine Blue Heron, FL | 10 – NG (24-hr CEMS)<br>17 – NG (DB&PA) | 1.2 – NG<br>6.6 – NG (DB&PA) | 31.9 lb/hr – NG (DB&PA)<br>10 percent Opacity<br>5 ppmvd Ammonia Slip | Clean Fuels<br>Good Combustion |
| Mobile Energy, AL | ~18 – NG<br>~26 – FO | ~5 – NG<br>~6 - FO | 10% Opacity | Clean Fuels<br>Good Combustion |
| Alabama Power Barry, AL | ~15 – NG(CT)<br>~25 – NG(DB & CT) | ~8 - NG(CT)<br>~12 – NG(CT & DB) | 0.010 lb/MMBtu – (CT)<br>0.011 lb/MMBtu -(CT/DB)<br>10% Opacity | Clean Fuels<br>Good Combustion |
| KUA Cane Island, FL | 10 - NG (CT)<br>20 - NG (CT&DB)<br>30 - FO | 1.4 - NG (CT)<br>4 - NG (CT&DB)<br>10 - FO | 10% Opacity | Clean Fuels<br>Good Combustion |

*Notes:*

CON = Continuous
SC = Simple Cycle
INT = Intermittent
DB = Duct Burner
DLN = Dry Low $NO_X$ Combustion
SCR = Selective Catalytic Reduction
HSCR = Hot SCR
CT = Combustion Turbine
FO = Fuel Oil
NG = Natural Gas
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
ABB = Asea Brown Bovari

# DRAFT PERMIT

**PERMITTEE:**

Florida Power
P.O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

*Authorized Representative:*
Bruce Baldwin, Vice President – Combustion Turbine Operations

| |
|---|
| Hines Energy Complex, Power Block 3<br>Project No. 1050234-006-AC<br>Air Permit No. PSD-FL-330<br>SIC No. 4911 |
| Expires: June 30, 2007 |

**PROJECT AND LOCATION**

This permit authorizes the construction of Power Block 3 at the existing Hines Energy Complex, a "2-on-1" combined cycle unit with an electrical generating capacity of approximately 530 megawatts (MW). The project will consist of two 170 MW gas turbine-electrical generator sets, two unfired heat recovery steam generator (HRSG) sets, and a single 190 MW steam turbine-electrical generator. The existing Hines Energy Complex is located in the southwest portion of Polk County, Florida, approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade. *{Permitting Note: Throughout this permit, the electrical generating capacities represent nominal values for the given operating conditions.}*

UTM Zone 17; 414.4 km East; 3073.9 km North (Latitude: 27° 47' 19", Longitude: 81° 52' 10")

**STATEMENT OF BASIS**

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

**CONTENTS**



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

## FACILITY DESCRIPTION

The existing Hines Energy Complex currently consists of one operating electrical generating unit (Power Block 1) and another electrical generating unit currently under construction (Power Block 2). Power Block 1 is a 485 MW combined cycle power generation unit that began operation in 1999. It consists of 2 combustion turbines, 2 HRSGs, and 1 steam turbine. Power Block 2, when complete, will include 2 combustion turbines, 2 HRSGs, and 1 steam turbine in a 530 MW power generation unit. After completion of this project (Power Block 3), the plant will have a total generating capacity of approximately 1,545 MW.

## NEW AND MODIFIED EMISSIONS UNITS

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

| ID | Emission Unit Description |
|---|---|
| 016 | Power Block 3, CT 3A (170 MW gas turbine with unfired HRSG) |
| 017 | Power Block 3, CT 3B (170 MW gas turbine with unfired HRSG) |

*{Permitting Note: Florida Power Hines Energy Complex Power Block 3 (Power Block 3, or "the project") consists of 2 gas turbine-electrical generator sets (Units CT 3A and CT 3B), 2 unfired HRSGs, and a single steam-turbine electrical generator.}*

## REGULATORY CLASSIFICATION

Title III: The existing facility is a major source of hazardous air pollutants (HAPs). This project, however, is not major for HAPs. Based on the available information, this project does not trigger the requirements for a case-by-case determination of the Maximum Available Control Technology (MACT) under Section 112(g) of the Clean Air Act (CAA, or "the Act"). This project may trigger a case-by-case MACT determination pursuant to Section 112(j) of the Act – the "MACT hammer." (See Appendix YY.)

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

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

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

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

## PERMITTING AUTHORITY

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

## COMPLIANCE AUTHORITY

All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department's Southwest District Air Program, Compliance/Enforcement Section, 3804 Coconut Palm Drive, Tampa, Florida 33619-8218.

## APPENDICES

The following Appendices are attached as part of this permit.

| | |
|---|---|
| Appendix AL | Acronym List |
| Appendix BD | Final BACT Determinations and Emissions Standards |
| Appendix CF | Citation Format and Definitions |
| Appendix GC | General Conditions |
| Appendix GG | NSPS Subpart GG Requirements for Gas Turbines |
| Appendix SC | Standard Conditions |
| Appendix XS | Semiannual NSPS Excess Emissions Report |
| Appendix YYYY | NESHAP Subpart YYYY and 112(j) MACT Hammer |

## REVIEWING AND PROCESSING SCHEDULE

| | |
|---|---|
| September 4, 2002 | Received permit application and fee |
| November 7, 2002 | Department's request for additional information (via Office of Siting Coordination's sufficiency questions) |
| December 19, 2002 | Received response to sufficiency questions |
| February 19, 2003 | Received report documenting commercial, residential, and industrial growth since August 7, 1977 |
| February 19, 2003 | Application complete |
| ^ DRAFT | Distributed Notice of Intent to Issue and supporting documents |
| ^ DRAFT | Notice of Intent to Issue published in ^ DRAFT |

## RELEVANT DOCUMENTS

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

- Permit application
- Department's request for additional information (Office of Siting Coordination sufficiency questions)
- Applicant's additional information
- Department's Technical Evaluation and Best Available Control Technology (BACT) Determination
- Department's Intent to Issue

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

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

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

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

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

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

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

## POWER BLOCK 3 COMBINED CYCLE GAS TURBINES (EUs 016 AND 017)

This section of the permit addresses the following emissions units.

**Emission Units 016 and 017**

**Description**: Emission units 016 and 017 each consist of a Siemens Westinghouse 501 FD gas turbine-electrical generator set, an automated gas turbine control system, and an unfired HRSG. In addition, the project also includes a single steam turbine-electrical generator that serves both gas turbine/HRSG systems.

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

**Generating Capacity**: Both of the gas turbine-electrical generator sets have a generating capacity of 170 MW for gas firing. Exhaust from each gas turbine passes through a separate HRSG. Steam from both HRSGs is delivered to the single steam turbine-electrical generator, which has a generating capacity of 190 MW. The total generating capacity of the "2-on-1" combined cycle unit is approximately 530 MW.

**Controls**: The efficient combustion of natural gas and restricted firing of low sulfur distillate oil minimizes the emissions of CO, $PM/PM_{10}$, SAM, $SO_2$ and VOC. Dry low-NOx (DLN) combustion technology for gas firing and water injection for oil firing reduce NOx emissions. A selective catalytic reduction (SCR) system – in combination with DLN combustion technology for gas firing and a water injection system for oil firing – reduces NOx emissions. The HRSGs are designed and constructed such that an oxidation catalyst can be readily installed if necessary to achieve compliance with CO emission limitations.

**Stack Parameters**: Each HRSG has a stack that is 125 feet tall and 19 feet in diameter. The Department may require the permittee to perform additional air dispersion modeling should the actual specified stack dimensions change. The following table summarizes the exhaust characteristics for the combined cycle systems. Heat input rate is based on the higher heating value (HHV) of the fuel, assuming 1,030 British thermal units (Btu) per standard cubic feet of natural gas and 19,892 Btu/lb of fuel oil.

| Fuel | Heat Input Rate (HHV) | Compressor Inlet Temp | Exhaust Temperature | Exit Velocity | Flow Rate |
|---|---|---|---|---|---|
| Gas | 1,830 MMBtu/hour | 59 °F | 190 °F | 59.2 ft/sec | 1,009,487 acfm |
| Oil | 1,932 MMBtu/hour | 59 °F | 270 °F | 67.0 ft/sec | 1,139,394 acfm |

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

### APPLICABLE STANDARDS AND REGULATIONS

1. BACT Determinations: Determinations of BACT were made for CO, NOx, $PM/PM_{10}$, sulfuric acid mist (SAM), $SO_2$, and VOC. See Appendix BD of this permit for a summary of the final BACT determinations. [Rule 62-212.400(BACT), F.A.C.]

2. New Source Performance Standards (NSPS): The Department determines that compliance with the BACT emissions performance and monitoring requirements also assures compliance with the NSPS for gas turbines at 40 CFR part 60, subpart GG. See Appendix GG of this permit for a summary of the applicable NSPS requirements. [Rule 62-204.800(7), F.A.C.]

### EQUIPMENT

3. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain two Siemens Westinghouse Model 501 FD gas turbine-electrical generator sets each with a generating capacity of

170 MW. Each gas turbine shall include the Siemens TXP automated gas turbine control system and have dual-fuel capability. The gas turbines will utilize DLN combustors. [Application; Design]

4. Gas Turbine NOx Controls

   a. *DLN Combustion*: The permittee shall operate and maintain the DLN combustion system to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   b. *Water Injection*: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

   c. *SCR System*: The permittee shall install, tune, operate, and maintain a SCR system to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Permitting Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.}*

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

5. HRSGs: The permittee is authorized to install, operate, and maintain two HRSGs. Each HRSG shall be designed to recover heat energy from one of the two gas turbines (CT 3A or CT 3B) and deliver steam to the steam turbine-electrical generator through a common manifold. *{Permitting Note: The two HRSGs deliver steam to a single steam turbine-electrical generator with a generating capacity of 190 MW.}* [Application; Design]

6. CO Controls: The permittee shall design and construct the HRSGs such that an oxidation catalyst can be readily installed if necessary to achieve compliance with the CO emission limitations. The oxidation catalyst, should it be installed, shall be designed and operated to achieve a maximum outlet concentration of 3.5 ppmvd corrected to 15% oxygen.

**PERFORMANCE RESTRICTIONS**

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is 1,915 MMBtu per hour when firing natural gas and 2,020 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59 °F, the HHV of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate fuels, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

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

   a. *Hours of Operation*: Subject to the other operational restrictions of this permit, the gas turbines may operate throughout the year (8,760 hours per year).

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 1.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Distillate fuel oil consumption of both emissions units shall not exceed 19,703,000 gallons in any consecutive 12 month period. *{Permitting Note: This condition limits annual average fuel oil consumption to the equivalent of approximately 720 hours of operation per year per turbine, based on 59 °F annual average temperature. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.}*

c. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a "2-on-1" combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

d. *Ammonia Injection*: Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer.

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

**EMISSIONS STANDARDS**

9. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | 5 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| $PM/PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| $SAM/SO_2$ [f] | Fuel specifications. |

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

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

f. The fuel sulfur specifications in Condition No. 8 of this section effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of this section.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}* [Rule 62-212.400(BACT), F.A.C.]

## EXCESS EMISSIONS

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

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

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

13. CEMS Data Exclusion: As provided in this paragraph, NOx and CO emissions data recorded during periods of startup, shutdown, oil-to-gas fuel switches, and documented malfunctions may be excluded from the

block average calculated to demonstrate compliance with the emission limits of Condition No. 9 of this section.

a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold startups. A "cold startup" is defined as a startup following a complete shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed four hours in any 24-hour block period.

b. Periods of data excluded for shutdown shall not exceed two hours in any 24-hour block.

c. Periods of data excluded for oil-to-gas fuel switches shall not exceed two hours in any 24-hour block.

d. Periods of data excluded for documented malfunctions shall not exceed two hours in any 24-hour block. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

e. All periods of data excluded for any startup, shutdown, oil-to-gas fuel switches, or documented malfunction shall be consecutive for each episode. Periods of data excluded for all startup, shutdown, oil-to-gas fuel switches, or documented malfunctions shall not exceed four hours in any 24-hour block.

f. The permittee shall minimize the duration of data excluded to the extent practicable. Data shall not be excluded if the startup, shutdown, or documented malfunction was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably have been prevented.

[Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

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

### EMISSIONS PERFORMANCE TESTING

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

| Method | Description of Method and Comments |
|---|---|
| CTM-027 | *Procedure for Collection and Analysis of Ammonia in Stationary Sources*<br>This is an EPA conditional test method. The minimum detection limit shall be 1 ppm. |
| 7E | *Determination of Nitrogen Oxide Emissions from Stationary Sources (Instrumental Analyzer Procedure)* |
| 9 | *Visual Determination of the Opacity of Emissions from Stationary Sources*<br>The test shall be conducted for a minimum of 30 minutes. |
| 10 | *Determination of Carbon Monoxide Emissions from Stationary Sources*<br>This method shall be based on a continuous sampling train. |

| Method | Description of Method and Comments |
|---|---|
| 18 | *Measurement of Gaseous Organic Compound Emissions by Gas Chromatography* (Optional) EPA Method 18 may be used concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions. |
| 20 | *Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines* |
| 25A | *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer* |

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

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

17. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. *{Permitting Note: Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of $PM/PM_{10}$ and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

18. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia.

    a. *Visible Emissions.* Each unit shall be tested for visible emissions when firing natural gas and when firing distillate fuel oil. Annual emissions testing while firing fuel oil is not required during any federal fiscal year in which less than 5,473,000 gallons of distillate fuel oil is fired in both emission units combined. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: The fuel limitation for waiving testing while firing distillate fuel oil corresponds to the equivalent of approximately 200 hours of operation per year per turbine.}*

    b. *Ammonia.* Annual testing to determine the ammonia slip shall be conducted while firing natural gas. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run.

    *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

19. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

**CONTINUOUS MONITORING REQUIREMENTS**

20. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NOx from the combined cycle gas turbine. The CEMS shall be used to demonstrate continuous compliance with the CEMS emission standards specified in this permit. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60. The Method 10 analysis shall be based on a continuous sampling train, and the ascarite trap may be omitted or the interference trap of Section 10.1 may be used in lieu of the silica gel and ascarite traps. The span for the CO monitor shall not be greater than 50 ppm, as corrected to 15% oxygen.

    b. *NOx Monitors.* The NOx monitor shall be certified pursuant to 40 CFR 75, and shall be operated and maintained in accordance with the applicable requirements of 40 CFR 75, Subparts B and C. Record keeping and reporting shall be conducted pursuant to 40 CFR 75, Subparts F and G. The RATA tests required for the NOx monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. The NOx monitor shall be a dual range monitor. The span for the lower range shall not be greater than 10 ppm, and the span for the upper range shall not be greater than 30 ppm, as corrected to 15% oxygen.

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

    d. *Moisture Correction.* Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. If the CEMS measures concentration on a wet basis, the CEMS shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the permittee may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0%

moisture). If the CEMS measures concentration on a wet basis and the diluent monitor measures $CO_2$ on a wet basis, then the permittee may develop an algorithm to enable correction of the CEMS results to a dry basis (0% moisture) without determining the corresponding moisture content.

e. *1-Hour Block Averages.* Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour.

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

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 13 and 14 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

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

*{Permitting Note: Compliance with these requirements assures compliance with the other applicable CEM system requirements such as: NSPS Subpart GG; Rule 62-297.520, F.A.C.; 40 CFR 60.7(a)(5) and 40 CFR 60.13; 40 CFR 60, Appendix B - Performance Specifications; and 40 CFR 60, Appendix F - Quality Assurance Procedures.}* [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

21. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and

record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards. During NOx CEMS downtimes or malfunctions, the permittee shall monitor the water-to-fuel ratio and operate at a level that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

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

**RECORDS AND REPORTS**

23. Monitoring of Operation: To demonstrate compliance with the fuel consumption and sulfur content limits of Condition No. 8 of this section, the permittee shall monitor and record the rates of consumption and sulfur content of each of the allowable fuels in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400, F.A.C., and BACT]

24. Frequency of Recordkeeping: Condition No. 20 of this section requires the calculation of one or more 24-hour block average emission rates for each operating day. Within 24 hours of the conclusion of each operating day, the permittee shall complete the calculations and record the results for that operating day. [Rule 62-4.070(3), F.A.C.]

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

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

    b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each Compliance Authority before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall either (1) maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor, or (2) take and analyze a sample according to the above procedures and maintain a permanent file of the results of the analysis. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

26. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Conditions Nos. 13 or 14 of this section, the permittee shall notify the Compliance Authority. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the

probable cause of the emissions; and the actions taken to correct the problem. If requested by the Compliance Authority, the permittee shall submit written quarterly reports summarizing the malfunctions in lieu of the individual malfunction notifications otherwise required. [Rule 62-210.700, F.A.C.]

27. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(c), the permittee shall semiannually submit a report to the Compliance Authority summarizing any emissions in excess of the NSPS standards. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the information specified in 40 CFR 60.7(c)(1) through (c)(4). For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG (i.e., 112.5 ppmvd corrected to 15% oxygen for both natural gas and fuel oil); and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG (i.e., sulfur in excess of 0.8% by weight). An example of an acceptable report format is provided in Appendix XS. [40 CFR 60.7(c)]

28. Quarterly Data Exclusion and Monitor Availability Report: The permittee shall quarterly submit a report to the Compliance Authority summarizing all periods of valid hourly CO and NOx emissions data excluded from the 24-hour block average compliance determinations pursuant to Condition Nos. 13 and 14 of this section. In addition, the quarterly report shall summarize the CEMS availability for the previous quarter. All reports shall be postmarked by the 30th day following the end of each calendar quarter. An example of an acceptable report format for monitoring systems availability is provided in Appendix XS. [Rules 62-4.130, 62-204.800; 62-210.700(6), F.A.C.; and 40 CFR 60.7(c) and (d)]

CONTENTS

## ACRONYM LIST

| | |
|---|---|
| acfm | Actual cubic feet per minute |
| ASTM | ASTM International [1] |
| BACT | Best Available Control Technology |
| Btu | British thermal unit |
| CAA, or "the ACT" | Clean Air Act, as amended in 1990 |
| CEMS | Continuous emission monitoring system |
| CFR | Code of Federal Regulations |
| CO | Carbon monoxide |
| $CO_2$ | Carbon dioxide |
| DLN | Dry-low NOx |
| EPA | U.S. Environmental Protection Agency |
| F.A.C. | Florida Administrative Code |
| F.S. | Florida Statutes |
| FDEP, or "the Department" | Florida Department of Environmental Protection |
| HAP | Hazardous air pollutant |
| HHV | Higher heating value |
| HRSG | Heat recovery steam generator |
| LAER | Lowest Achievable Emission Rate |
| LHV | Lower heating value |
| MMBtu | Million British thermal units |
| MW | megawatt |
| NAAQS | National Ambient Air Quality Standards |
| NESHAP | National Emission Standards for Hazardous Air Pollutants |
| NOx | Nitrogen oxides |
| NSPS | New Source Performance Standards |
| $PM/PM_{10}$ | Particulate matter |
| PSD | Prevention of Significant Deterioration |
| RACT | Reasonably Available Control Technology |
| RATA | Relative accuracy test assessment |
| SCR | Selective catalytic reduction |
| SNCR | Selective non-catalytic reduction |
| $SO_2$ | Sulfur dioxide |
| VOC | Volatile organic compound |

[1] Formerly known as American Society for Testing and Materials.

## FINAL BACT DETERMINATIONS AND EMISSIONS STANDARDS

### OVERVIEW

The project added a 530 megawatt (MW) "2-on-1" combined cycle gas turbine system to the existing Florida Power Hines Energy Complex. Significant emissions increases pursuant to the Prevention of Significant Deterioration (PSD) rule required determinations of the Best Available Control Technology (BACT) for carbon monoxide (CO), nitrogen oxides (NOx), particulate matter ($PM/PM_{10}$), sulfuric acid mist (SAM), sulfur dioxide ($SO_2$), and volatile organic compounds (VOC).

### BACT CONTROL TECHNOLOGIES

The Florida Department of Environmental Protection (the "Department") reviewed available control technologies for each pollutant resulting in a PSD-significant increase. The Department's technical review and rationale for the BACT determinations are presented in the "Technical Evaluation and Preliminary Determination" as revised prior to the siting hearing. The following summarizes the control technologies upon which the Department's final BACT determinations are based.

<u>BACT for CO Emissions</u>

*Good Combustion and Operating Practices*: BACT for CO emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. Siemens Westinghouse's dual-fuel combustors have demonstrated very low CO emissions while simultaneously reducing NOx emissions for gas and oil firing.

*Catalytic Oxidation*: At the anticipated CO emissions rate, the Department does not consider the addition of a catalytic oxidation system for control of CO to be cost-effective. Catalytic oxidation – while not BACT – must be considered in the design of the heat recovery steam generators. The design must be such that the oxidation catalyst system can be readily installed in the future. If the as-built combined cycle unit cannot achieve the BACT CO emission limit, however, then the cost-effectiveness of the catalytic oxidation system improves and the Department shall require it to be installed.

<u>BACT for NOx Emissions</u>

*Dry Low-NOx (DLN) Combustion*: When firing natural gas, BACT for NOx emissions is the operation of Siemens Westinghouse's DLN combustion system. The efficient fuel combustion and thorough mixing of the gas stream reduces hot and cold spots surrounding the combustion zone. The full lean premix combustion results in low NOx emissions. The control system continuously monitors performance parameters and adjusts for efficient operation. The control system also provides for quick automated startups, lean pre-mix combustion performance, and controlled shutdowns.

*Wet Injection*: When firing distillate oil, BACT for NOx emissions is the operation of Siemens Westinghouse's dual-fuel combustor with wet injection designed to reduce the flame temperature and lower NOx emissions.

*Selective Catalytic Reduction (SCR)*: When firing natural gas or distillate oil, BACT for NOx emissions is the operation of the SCR system in conjunction with DLN combustion and wet injection. Ammonia injected into the exhaust gas stream combines with NOx in a reduction action across a catalyst bed to form nitrogen and water. The catalyst bed is located after the heat recovery steam generator, which reduces exhaust temperatures to the appropriate operating range of the catalyst material. The SCR system will achieve about a 70% reduction with an initial ammonia slip of no more than 5 ppmvd.

<u>BACT for VOC Emissions</u>

*Good Combustion and Operating Practices*: BACT for VOC emissions is the efficient combustion of fuels at high temperatures associated with good combustion design and operating practices. Siemens Westinghouse's dual-fuel combustors have demonstrated very low VOC emissions while simultaneously reducing NOx emissions for gas and oil firing.

BACT for PM, SAM, and SO2 Emissions

*Fuel Specifications*: BACT for PM, SAM, and SO2 emissions is the use of natural gas as the primary fuel ($\leq$ 1.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil ($\leq$ 0.05% sulfur by weight). These fuels are readily combustible and contain little ash, sulfur, or other contaminants.

**BACT STANDARDS**

The following summarizes the final BACT determinations for this project in accordance with Rule 62-212.400 (BACT), F.A.C.

| Pollutant | Emission Limit (ppmvd corrected to 15% oxygen) | | Averaging Time |
|---|---|---|---|
| | Natural Gas | Fuel Oil | |
| CO [a] | 10 | 20 | 24 hour block |
| NOx [b] | 2.5 | 10 | 24 hour block |
| VOC [c] | 2 | 10 | 3 hours |
| Ammonia [d] | 5 | 5 | 3 hours |

| Pollutant | Fuel Specification and Emission Limit |
|---|---|
| PM/$PM_{10}$ [e] | Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average. |
| SAM/$SO_2$ [f] | Fuel specifications. |

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance with the 24-hour CO CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. NOx mass emission rates are defined as oxides of nitrogen expressed as $NO_2$. Compliance with the 24-hour NOx CEMS standards shall be determined separately based on the hours of operation for each alternative fuel. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

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

d. Subject to the requirements of Condition No. 19 of Section III of this permit, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

e. The fuel specifications established in Condition No. 8 of Section III of this permit – combined with the efficient combustion design and operation of each gas turbine – represents the BACT determination for PM/$PM_{10}$ emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

f. The fuel sulfur specifications in Condition No. 8 of Section III of this permit effectively limit the potential emissions of SAM and $SO_2$ from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. 25 of Section III of this permit.

*{Permitting Note: The concentration limits and fuel specifications for the control of the above pollutants are equivalent to the following mass emission rates (at 20 °F):*

- *CO = 46 lb/hr for natural gas firing and 75 lb/hr for distillate fuel oil firing,*
- *NOx = 17.9 lb/hr for natural gas firing and 76.9 lb/hr for distillate fuel oil firing,*
- *VOC =5.3 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *$PM_{10}$ = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *$SO_2$ = 5.6 lb/hour for natural gas firing and 105.6 lb/hr for distillate fuel oil firing.*

*SAM emissions are estimated to be less than 10% of the $SO_2$ emissions.}*

If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall: begin testing and reporting the ammonia slip for each subsequent calendar quarter; before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions. Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis.

**FINAL BACT DETERMINATIONS**

As summarized above, the Department determines that the standards specified in this permit represent BACT for emissions of CO, NOx, PM/$PM_{10}$, SAM, $SO_2$, and VOC. The Department's technical review and rationale for the BACT determinations are presented in Technical Evaluation and Preliminary Determination issued concurrently with the draft permit.

*Determination By:*

^ DRAFT

Gregory P. DeAngelo, P.E., Project Engineer
New Source Review Section

*Recommended By:*

^ DRAFT

Trina Vielhauer, Chief
Bureau of Air Regulation

*Approved By:*

^ DRAFT

Howard L. Rhodes, Director
Division of Air Resources Management

## CITATION FORMAT AND DEFINITIONS

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

### REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

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

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

New Permit Numbers

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

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

PSD Permit Numbers

*Example*: Permit No. PSD-FL-330

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

### RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

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

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

Code of Federal Regulations (CFR)

*Example*: [40 CFR 60.7]

*Means*: Title 40, Part 60, Section 7 of the Code of Federal Regulations

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

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

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

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

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

## GENERAL CONDITIONS

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

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

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

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

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

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

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

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

   a. Have access to and copy and records that must be kept under the conditions of the permit;

   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,

   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);

    b. Determination of Prevention of Significant Deterioration (X); and

    c. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        1) The date, exact place, and time of sampling or measurements;

        2) The person responsible for performing the sampling or measurements;

        3) The dates analyses were performed;

        4) The person responsible for performing the analyses;

        5) The analytical techniques or methods used; and

        6) The results of such analyses.

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

## NSPS SUBPART GG REQUIREMENTS FOR GAS TURBINES

Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR Part 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine has a heat input at peak load equal to or greater than 10 MMBtu per hour (LHV) and will commence construction after October 3, 1977. Therefore, the gas turbines are subject to NSPS Subpart GG. [40 CFR 60.330(a) and (b), Applicability and Designation of Affected Facility.]

Emissions units subject to a NSPS are also subject to the applicable requirements of 40 CFR Part 60, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

### § 60.331 Definitions.

The following applicable terms are defined by this subpart:

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

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

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

(g) ISO standard day conditions 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.

(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 § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

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

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

where:

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

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

F = NOx emission allowance for fuel-bound nitrogen as defined in § 60.332(a)(3).

(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) |
|---|---|
| $N \leq 0.015$ ........................................ | 0 |
| $0.015 < N \leq 0.1$ .............................. | 0.04(N) |
| $0.1 < N \leq 0.25$ ................................ | 0.004+0.0067(N–0.1) |
| $N > 0.25$ ........................................ | 0.005 |

where:

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

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

**[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" values provided by the applicant are approximately 9.6 for both natural gas and fuel oil. The equivalent emission standards are 112.5 ppmvd at 15% oxygen. The BACT limits of this permit are more stringent than this requirement.]**

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

**§ 60.333 Standard for Sulfur Dioxide.**

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

(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.

**[Note: The BACT limits of this permit are more stringent than this requirement.]**

**§ 60.334 Monitoring of Operations.**

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

(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.

<u>Department requirement</u>: **The owner or operator is allowed to use vendor analyses of the fuel as received to satisfy the sulfur content monitoring requirements of this rule for fuel oil. Alternatively, if the fuel oil storage tank is isolated from the combustion turbines while being filled, the owner or operator is allowed to determine the sulfur content of the tank after completion of filling of the tank, before it is placed back into service.**

**[Note: This is consistent with guidance from EPA Region 4 dated May 26, 2000 to Ronald W. Gore of the Alabama Department of Environmental Management.]**

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

**Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. The requirement to monitor the nitrogen content of fuel oil fired is waived because a NOx CEMS shall be used to demonstrate compliance with the NOx limits of this permit. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator is allowed to determine the sulfur content of the pipeline quality natural gas semi-annually, because the owner or operator has the results of bimonthly and quarterly natural gas sulfur content analyses from the operation of the existing Power Block 1.**

**[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]**

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

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

**Department requirement: NOx emission monitoring by CEMS shall substitute for the requirements of paragraph (c)(1) because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 as described in Condition No. 27 of Section III of this permit.**

**Department requirement: NOx and CO monitor availability shall not be less than 95% in any calendar quarter. The report required by Condition No. 28 of Section III of this permit shall be used to demonstrate compliance with this requirement.**

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

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

### § 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 per-cent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

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

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

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

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

where:

NOx = emission rate of NOx at 15 percent O2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

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

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

Ho = observed humidity of ambient air, g H2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

**Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.**

**[Note: This is consistent with guidance from EPA Region 4.]**

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

**Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.**

**[Note: This is consistent with guidance from EPA Region 4.]**

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

**Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEMS data, provided that compliance be based on a**

**minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in Condition No. 20 of Section III of this permit shall be used instead of the span value of 300 ppm specified by paragraph (3) above.**

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

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

<u>Department requirement</u>: **Condition No. 25 of Section III of this permit requires the owner or operator to follow the requirements of 40 CFR 75 Appendix D to determine the sulfur content of liquid fuels.**

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

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

**[Note: The fuel analysis requirements of Condition No. 25 of Section III of this permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]**

## STANDARD CONDITIONS

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

### EMISSIONS AND CONTROLS

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

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

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

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

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

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

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

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

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

### TESTING REQUIREMENTS

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

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

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

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

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

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

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

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

14. Determination of Process Variables

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

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

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

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

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

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

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

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

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

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

**RECORDS AND REPORTS**

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

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

## SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

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

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

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

Reporting period dates: From ____________________ to ____________________

Company: ____________________

Emission Limitation: ____________________

Address: ____________________

Monitor Manufacturer: ____________________

Model No. : ____________________

Date of Latest CMS Certification or Audit: ____________________

Process Unit(s) Description: ____________________

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

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

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

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

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

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

*Name*: ____________________

*Signature*: ____________________ *Date*: ____________________

*Title*: ____________________

## NESHAP SUBPART YYYY AND 112(J) MACT HAMMER

### APPLICABILITY

The Power Block 3 gas turbines are regulated as emissions units 016 and 017. Each Power Block 3 gas turbine is a "stationary combustion turbine located at a major source of HAP emissions" and will commence construction after January 14, 2003. Therefore, the gas turbines will be subject to the new source requirements of the combustion turbines NESHAP, 40 CFR 63, Subpart YYYY, when that subpart is finalized.

Emissions units subject to a NESHAP are also subject to the applicable requirements of 40 CFR Part 63, Subpart A, General Provisions. Individual subparts may exempt specific equipment or processes from some or all of the general provisions. For brevity, the general provisions are not duplicated in this permit. A copy of the most recently updated general provisions may be provided in full upon request.

### TIMING AND REQUIREMENTS

The combustion turbines NESHAP was proposed on January 14, 2003. It is currently scheduled for promulgation by August 30, 2003. If the combustion turbines NESHAP is promulgated prior to startup of the Power Block 3 combustion turbines, then:

- The permittee shall apply for a permit revision to this permit to incorporate the relevant requirements of 40 CFR 63, Subparts A and YYYY, and ensure compliance with those standards prior to startup of the Power Block 3 combustion turbines.

If, however, the combustion turbines NESHAP is not promulgated prior to startup of the Power Block 3 combustion turbines, then:

- Within 30 days of startup of the Power Block 3 combustion turbines, the permittee shall submit a "Part 1 MACT application" as specified in the Section 112(j) rules, currently located at 40 CFR 63.53(a).
- If 40 CFR 63, Subpart YYYY, is promulgated within 24 months of submitting the Part 1 MACT application, then the permittee shall apply for a permit revision to this permit to incorporate the relevant requirements of 40 CFR 63, Subpart YYYY, and ensure compliance with those standards prior to the date 24 months following submittal of the Part 1 MACT application.
- If 40 CFR 63, Subpart YYYY, is not promulgated within 24 months of submitting the Part 1 MACT application, then the permittee shall submit a "Part 2 MACT application" as specified in the Section 112(j) rules, currently located at 40 CFR 63.53(b). The Part 2 MACT application shall be submitted prior to the date 24 months following submittal of the Part 1 MACT application.

[Rule 62-4.070(3), F.A.C. See also 40 CFR 60.6085, proposed at 68 FR 1888, January 14, 2003.]

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Bruce Baldwin
Vice President, Combustion Turbine Operations
Florida Power
P. O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

***COMPLETE THIS SECTION ON DELIVERY***

A. Signature
X D. Clark ☐ Agent ☐ Addressee

B. Received by (*Printed Name*) D Clark

C. Date of Delivery

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

ST. PETERSBURG FL 33733
MAR 07 2003
CALLER SERVICE

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☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail

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

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PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

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City, State, ZIP+4: St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

**Florida Power**
A **Progress Energy** Company

RECEIVED
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BUREAU OF AIR REGULATION

February 10, 2003

Mr. Greg DeAngelo
Florida Department of Environmental Protection
Bureau of Air Regulation, New Source Review Section
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Re: **Hines Energy Complex - Power Block 3**
**Additional Information Related to**
**Project No. 1050234-006-AC/Air Permit No. PSD-FL-330 and**
**Supplemental Site Certification Application to PA 92-33**

Dear Mr. DeAngelo:

Please find enclosed additional information relating to the air quality impacts of, and the nature and extent of, all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977 in the area of this proposed project. This information is provided to supplement the information provided in the above referenced application and to fully satisfy the requirements of 62-212.400(3)(h)(5), F.A.C.

Should you have any questions regarding this information, please contact me at (813) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

jjh/JJH055

Enclosure

c/enc: Hamilton Oven – FDEP Siting Office
Doug Roberts – HG&S

# HINES ENERGY COMPLEX, POWER BLOCK 3
# GENERAL, RESIDENTIAL, COMMERCIAL, INDUSTRIAL GROWTH

In support of Progress Energy's response to Florida Department of Environmental Protection (FDEP) sufficiency questions, December 18, 2002, Progress Energy submits the following information to satisfy the requirements of 62-212.400(3)(h)(5), Florida Administrative Code (F.A.C.), which states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general, residential, commercial, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. This information is consistent with the EPA Guidance related to this requirement in the Draft New Source Review Workshop Manual (1990).

In general, there has been minimal residential, commercial, and industrial growth within a 5-mile radius of the Hines Energy Complex site since 1977. The site is located in Polk County in central Florida and is the fourth largest county in Florida consisting of 1,823 square miles. The site lies in a region of the state dominated by phosphate mining operations including mines, settling ponds, sand tailings piles, gypsum stacks, and chemical and beneficiation plants. The site itself consists of approximately 8,000 acres that is wholly owned by Progress Energy. The adjacent land uses consist almost entirely of active phosphate mining, or mined and reclaimed lands. See Figure 2.2.3-2 of the Supplemental Site Certification Application (SSCA). From the standpoint of land use compatibility, the availability of transportation facilities, the lack of noise and visual impacts during construction and operation activities, the Siting Board has already determined the site location to be suitable for power plant facilities. A discussion of land use in the area of the Hines Energy Complex site is presented in Section 2.2 of the SSCA.

The following discussion presents general trends in residential, commercial, industrial, and other growth that has occurred since August 7, 1977, in Polk County. As such, the information presents information available from a variety of sources (e.g., Florida Statistical Abstract, FDEP) that characterizes Polk County as a whole.

## RESIDENTIAL GROWTH

### POPULATION AND HOUSEHOLD TRENDS

As an indicator of residential growth, the trend in the population and number of single- and multi-family household units in Polk County since 1977 are shown in Figure 1.

Over 3 million people live within a 50-mile radius and 6 million within a 100-mile radius of the Polk County. The county experienced a 73 percent increase in population for the years 1977 through 2000. During this period, there was an increase in population of about 204,000 with about 123,000 due to births and the rest from people moving into the county.

Similarly, the number of households in the county increased by about 68,000 or about 58 percent since 1977.

**GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT**

The nearest community to the project is the unincorporated community of Homeland that is approximately 1 mile northeast of the site boundary. There are very few residences near the plant site. Because of the limited number of workers needed to operate the project, residential growth due to the project is expected to be minimal.

**COMMERCIAL GROWTH**

**RETAIL TRADE AND WHOLESALE TRADE**

As an indicator of commercial growth in Polk County, the trends in the number of commercial facilities and employees involved in retail and wholesale trade are presented in Figure 2. The retail trade sector comprises establishments engaged in retailing merchandise. The retailing process is the final step in the distribution of merchandise. Retailers are, therefore, organized to sell merchandise in small quantities to the general public. The wholesale trade sector comprises establishments engaged in wholesaling merchandise. This sector includes merchant wholesalers who buy and own the goods they sell; manufacturers' sales branches and offices who sell products manufactured domestically by their own company; and agents and brokers who collect a commission or fee for arranging the sale of merchandise owned by others.

Since 1977 retail trade has increased by 524 establishments and 21,000 employees or 38 and 108 percent, respectively. For the same period, wholesale trade has increased by 413 establishments and 4,600 employees or 107 and 98 percent, respectively.

**LABOR FORCE**

The trend in the labor force in Polk County since 1977 is shown in Figure 3. The county is designated as a labor surplus area by the U.S Department of Labor. The unskilled labor supply consistently exceeds local demand. The estimated unemployment rate for 2000 was 4.7 percent.

Between 1977 and 1999, approximately 88,600 persons were added to the available work force for an increase of 85 percent.

**TOURISM**

Another indicator of commercial growth in Polk County is the tourism industry. As an indicator of tourism growth in the county, the trend in the number of hotels and motels and the number of units at the hotels and motels are presented in Figure 4.

This industry comprises establishments primarily engaged in marketing and promoting communities and facilities to businesses and leisure travelers through a range of activities, such as assisting organizations in locating meeting and convention sites; providing travel information on area attractions, lodging accommodations, restaurants; providing maps; and organizing group tours of local historical, recreational, and cultural attractions.

Between 1978 and 2000, there was a decrease of about 25 percent in the number of hotels and motels in the county; however there was a slight increase of 7 percent in the number of units at those facilities.

**TRANSPORTATION**

As an indicator of transportation growth, the trend in the number of vehicle miles traveled (VMT) by motor vehicles on major roadways in Polk County is presented in Figure 5. The county is the center of Florida's industrial belt and is within 500 miles of 40 major metropolitan areas.

The county straddles Interstate I-4, the main conduit for the central Florida growth corridor. Interstate I-4 connects with Interstate I-75 between Lakeland and Tampa (16 miles west of Lakeland to the interchange). Interstate I-4 extends from Orlando in the east, connecting with the Florida Turnpike, and continues to Daytona where it connects with Interstate I-95. Other major highways in the county include U.S Highways 27, 60, 92, and 98.

Between 1977 and 2001, there was an increase of about 5,100,000 VMT or 62 percent in the amount of travel by motor vehicles on major roadways in the county.

**GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT**

The existing commercial and transportation infrastructure should be adequate to provide any support services that might be required during construction and operation of the project. The workforce needed to operate the proposed project is expected to be about 12 workers that represent a small fraction of the labor force present in the immediate and surrounding areas.

**INDUSTRIAL GROWTH**

**UTILITIES**

Existing power plants in Polk County include the following:

- Ridge Generating Station;
- TECO Polk Power Station;
- Lakeland Electric McIntosh Plant;
- Lakeland Electric Larsen Plant;
- Calpine Auburndale Plant;
- Orange Cogen Plant;
- Mulberry Cogen Plant;
- Progress Energy, Hines Energy Complex, Power Block 1; and
- Progress Energy Tiger Bay Plant.

Together, these power plants have an electrical generating capacity of over 2,300 megawatts (MW).

Proposed sources that have received air permits or sources under construction include the following:

- CPV Pierce;
- Calpine Osprey Plant;
- Lakeland Electric Winston Peaking Station;
- Decker Peace River Plant;
- Calpine Auburndale Unit 2;
- TECO Polk Modification; and
- Progress Energy, Hines Energy Complex, Power Block 2.

Together, these power plants have a proposed electrical generating capacity of over 2,200 megawatts (MW).

As an indicator of electrical utility growth, the electrical generation capacity in Polk County since 1977 is shown in Figure 6.

**MINING, MANUFACTURING, AND CITRUS INDUSTRIES**

As an indicator of industrial growth, the trend in the number of employees in the mining and manufacturing industries in Polk County since 1977 are shown in Figure 7. As shown, the mining industry has experienced a decrease of 36 percent in the number of employees since 1977. Meanwhile, the manufacturing industry has experienced a slight increase of 5 percent in the number of employees.

As another indicator of industrial growth, the trend in the number of boxes of citrus produced in Polk County since 1977 is also shown in Figure 7. The citrus industry has experienced increases in the 1980s and early 1990s but, since 1977, has decreased by 22 percent.

**GROWTH ASSOCIATED WITH THE OPERATION OF THE PROJECT**

Since the baseline date of August 7, 1977, there have been only a few major facilities built within a 10-mile radius of the plant site including but not limited to: Orange Cogen Plant, TECO Polk Power Station, Progress Energy Tiger Bay Plant, and Mulberry Cogen Plant. These facilities consist of combustion turbines primarily operating in combined cycle mode and firing natural gas. Based on their locations in different areas around the Hines Energy Complex, it is not expected that there will be concentrated industrial/commercial growth due to the operation of the project.

**AIR QUALITY DISCUSSION**

**AIR EMISSIONS AND SPATIAL DISTRIBUTION OF MAJOR FACILITIES**

The spatial distribution of major air pollutant facilities in Polk County is shown in Figure 8. Based on actual emissions reported in 1999, total emissions of stationary sources from the county are as follows:

- $SO_2$: 31,900 TPY;
- Particulate matter with diameter of 10 microns or less ($PM_{10}$): 1,100 TPY;
- Nitrogen oxides ($NO_x$): 10,200 TPY;
- Carbon monoxide (CO): 1,050 TPY; and
- Volatile organic compounds (VOC): 320 TPY.

## AIR EMISSIONS FROM MOBILE SOURCES

The trends in the air emissions of CO, VOC, and $NO_x$ from mobile sources are presented in Figure 9. Between 1977 and 2002, there were significant decreases in these emissions. The decrease in CO, VOC, NO emissions were about 81, 7, and 4 tons per day, respectively, which represent decreases of 80, 80, and 56 percent, respectively, from 1977 emission estimates.

## AIR MONITORING DATA

Since 1977, Polk County has been classified as attainment for all criteria pollutants. There are currently four air quality monitors that are operated by the FDEP in Polk County. These monitors measure sulfur dioxide ($SO_2$) concentrations (Mulberry and Nichols), $PM_{10}$ concentrations (Mulberry and Nichols), and ozone (two sites in Lakeland). Data collected from these stations are considered to be representative of air quality in Polk County. A summary of the maximum pollutant concentrations measured in Polk County from 1998 through 2001 is presented in Table 2.3.7-7 of the SSCA application.

These data indicate that the maximum air quality concentrations measured in the region comply with and are well below the applicable ambient air quality standards. These monitoring stations are generally located in areas where the highest concentrations of a measured pollutant is expected due to the combined effect of emissions from stationary and mobile sources as well as meteorology. Therefore, the ambient concentrations in areas not monitored should have pollutant concentrations less than those monitored concentrations.

In addition, since 1977, $SO_2$ and PM in the form of $PM_{10}$ or total suspended particulates (TSP) have been collected in the county at numerous monitoring stations. Ozone data have been collected at several monitoring stations in the county since 1992.

### $SO_2$ Concentrations

The trends in the annual, 24-hour, and 3-hour average $SO_2$ concentrations measured in Polk County since 1977 are presented in Figures 10 through 12, respectively. $SO_2$ concentrations have been measured at more than 15 stations for various time periods throughout these years. The information presented in these figures is for those stations which operated for more than one year from 1977 through 2002.

As shown in these figures, measured $SO_2$ concentrations have been and continue to be well below the AAQS.

**$PM_{10}$/TSP Concentrations**

The trends in the annual and 24-hour average $PM_{10}$ and total suspended particulate (TSP) concentrations measured in Polk County since 1977 are presented in Figures 13 and 14, respectively. TSP concentrations are presented through 1988 since the AAQS was based on TSP concentrations through that year. In 1988, the TSP AAQS was revoked and the PM standard was revised to $PM_{10}$. TSP, and $PM_{10}$ concentrations have been measured at more than 20 stations for various time periods throughout these years. Similar to the $SO_2$ concentrations, the information presented in these figures is for those stations which operated for more than one year from 1977 through 2002.

As shown in these figures, measured TSP concentrations were generally below the TSP AAQS although, at several monitors, the TSP concentrations approached and exceeded the AAQS. Since 1988 when $PM_{10}$ concentrations have been measured, the $PM_{10}$ concentrations have been and continue to be below the AAQS.

**Ozone Concentrations**

The trends in the 1-hour and 8-hour average ozone concentrations measured in Polk County since 1991 are presented in Figures 15 and 16, respectively. Ozone concentrations were not measured in Polk County prior to 1991. Ozone concentrations have been measured at four stations since 1991.

As shown in these figures, measured ozone concentrations have approached but have not exceeded the AAQS. This trend is similar to measured ozone concentrations in surrounding counties that exhibit similar trends as those for Polk County. Ozone is a regional pollutant that is produced due to the interaction of regional VOC and $NO_x$ emissions with sunlight. These emissions originate not only in Polk County but from adjacent counties to produce ozone concentrations across the region.

**AIR MODELING ANALYSES FOR THE PROJECT**

Additionally, results of air modeling analyses demonstrate that the Project will comply with all applicable AAQS and PSD Class II and I increments. In fact, the project's maximum impacts are predicted to be below the significant impact levels in PSD Class II and I areas.

## CONCLUSIONS

Because of the minimal number of operational workers required for the project, the limited amount of current and expected commercial and industrial development around the existing plant site, and the low predicted impacts of the project in an area that currently complies and is anticipated to comply with ambient air quality standards, the air quality associated with the general, residential, commercial, and industrial growth in the county which has occurred since August 7, 1977 is expected to remain below ambient standards once the project is constructed and operated.

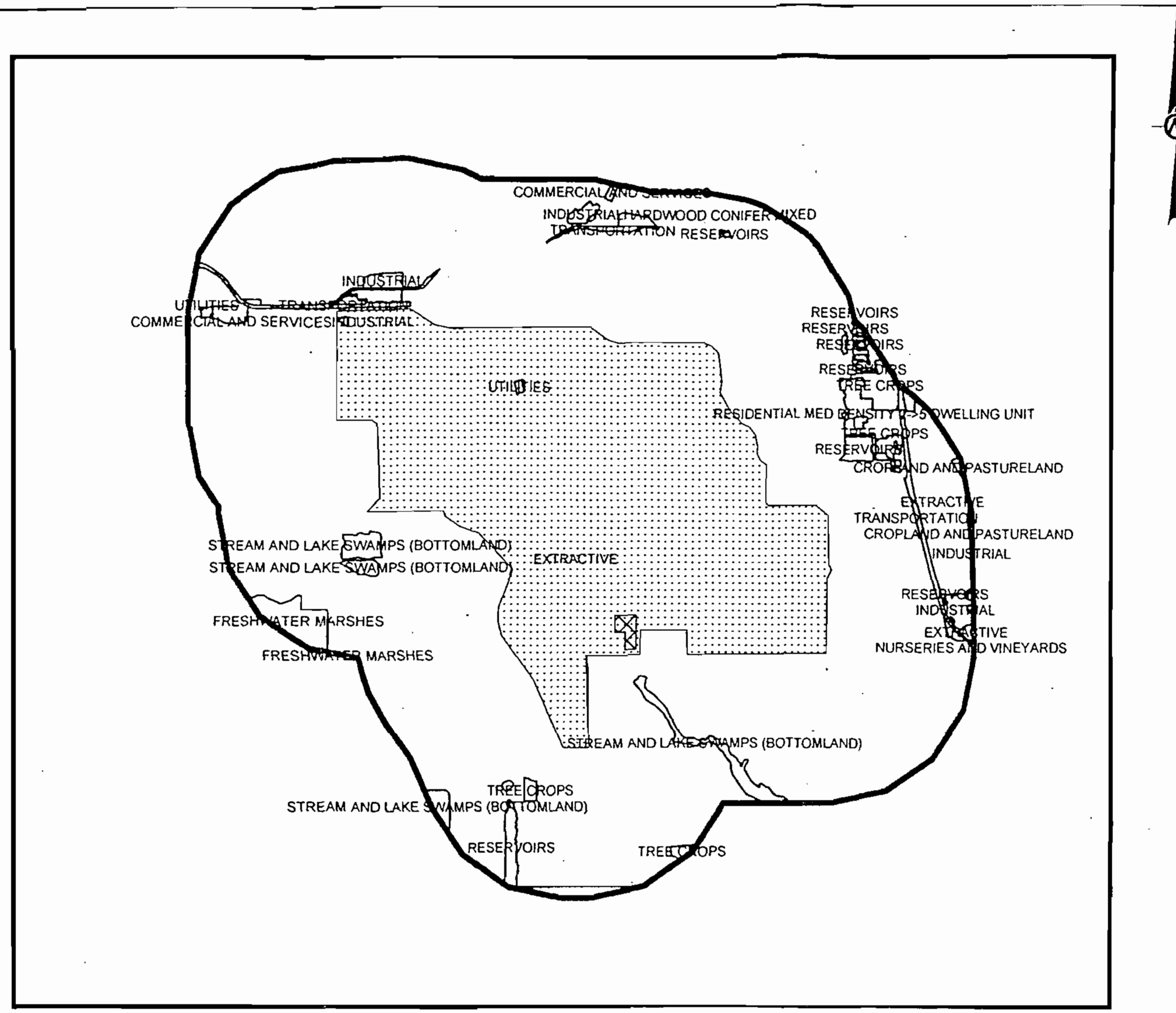
Table 2.3.7-7. Summary of Maximum Measured $SO_2$, $PM_{10}$, $O_3$, and $NO_2$ Concentrations Representative of the Hines Energy Complex, 1998 to 2001

| AIRS/ Saroad Site No. | Operator | Location | Measurement Period Year | Months | 1-Hour Highest | 1-Hour 2nd Highest | 3-Hour Highest | 3-Hour 2nd Highest | 8-Hour 3-year Average 4th Highest | 24-Hour Highest | 24-Hour 2nd Highest | Annual Average |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Sulfur dioxide** | | **Florida AAQS** | | | **NA** | **NA** | **NA** | **0.5 ppm** | **NA** | **NA** | **0.1 ppm** | **0.02 ppm** |
| 2860006F02 | Polk County | Mulberry | 1998 | Jan-Dec | NA | NA | 0.078 | 0.069 | NA | 0.029 | 0.027 | 0.006 |
| | | | 1999 | Jan-Dec | NA | NA | 0.070 | 0.052 | NA | 0.019 | 0.019 | 0.006 |
| | | | 2000 | Jan-Dec | NA | NA | 0.074 | 0.062 | NA | 0.022 | 0.018 | 0.005 |
| | | | 2001 | Jan-Dec | NA | NA | 0.059 | 0.048 | NA | 0.018 | 0.017 | 0.005 |
| **$PM_{10}$** [a] | | **Florida AAQS** | | | **NA** | **NA** | **NA** | **NA** | **NA** | **NA** | **150 µg/m³** | **50 µg/m³** |
| 121052006-1 | Polk County | Mulberry | 1998 | Jan-Dec | NA | NA | NA | NA | NA | 108 | 91 | 22.2 |
| | | | 1999 | Jan-Dec | NA | NA | NA | NA | NA | 50 | 50 | 20.8 |
| | | | 2000 | Jan-Dec | NA | NA | NA | NA | NA | 46 | 45 | 25.4 |
| | | | 2001 | Jan-Dec | NA | NA | NA | NA | NA | 74 | 59 | 22.6 |
| **Ozone** [a] | | **Florida AAQS** | | | **NA** | **0.12 ppm** | **NA** | **NA** | **0.08 ppm** | **NA** | **NA** | **NA** |
| 121056006-1 | Polk County | Lakeland | 1998 | Jan-Dec | 0.119 | 0.106 | NA | NA | NA | NA | NA | NA |
| | | | 1999 | Jan-Dec | 0.103 | 0.101 | NA | NA | NA | NA | NA | NA |
| | | | 2000 | Jan-Dec | 0.106 | 0.102 | NA | NA | NA | NA | NA | NA |
| | | | 2001 | Jan-Dec | 0.113 | 0.106 | NA | NA | NA | NA | NA | NA |
| **Nitrogen dioxide** | | **Florida AAQS** | | | **NA** | **NA** | **NA** | **NA** | **NA** | **NA** | **NA** | **0.053 ppm** |
| 120570081-1 | Hillsborough | Tampa | 1998 | Jan-Dec | NA | NA | NA | NA | NA | NA | NA | 0.006 |
| | | | 1999 | Jan-Dec | NA | NA | NA | NA | NA | NA | NA | 0.007 |
| | | | 2000 | Jan-Dec | NA | NA | NA | NA | NA | NA | NA | 0.008 |
| | | | 2001 | Jan-Dec | NA | NA | NA | NA | NA | NA | NA | 0.007 |

Note: NA = not applicable.
AAQS = ambient air quality standard.

[a] On July 18, 1997, EPA promulgated revised AAQS for particulate matter and ozone. For particulate matter, $PM_{2.5}$ standards were introduced with a 24-hour average standard of 65 µg/m³ (based on the 3-year averages of the 98th percentile values) and an annual standard of 15 µg/m³ (3-year averages at community monitors). The form of the 24-hour $PM_{10}$ standard was changed; compliance is based on 3-year average of 99th percentile concentrations that is 150 µg/m³ or less. The $O_3$ standard was modified to be 0.08 ppm for the 8-hour average; achieved when the 3-year average of 99th percentile values is 0.08 ppm or less. The courts have stayed these standards. Florida DEP has not yet adopted the revised standards.

Drawing file: 0237539A046 fig 2_2_3_2.dwg Aug 21, 2002 - 3:34pm



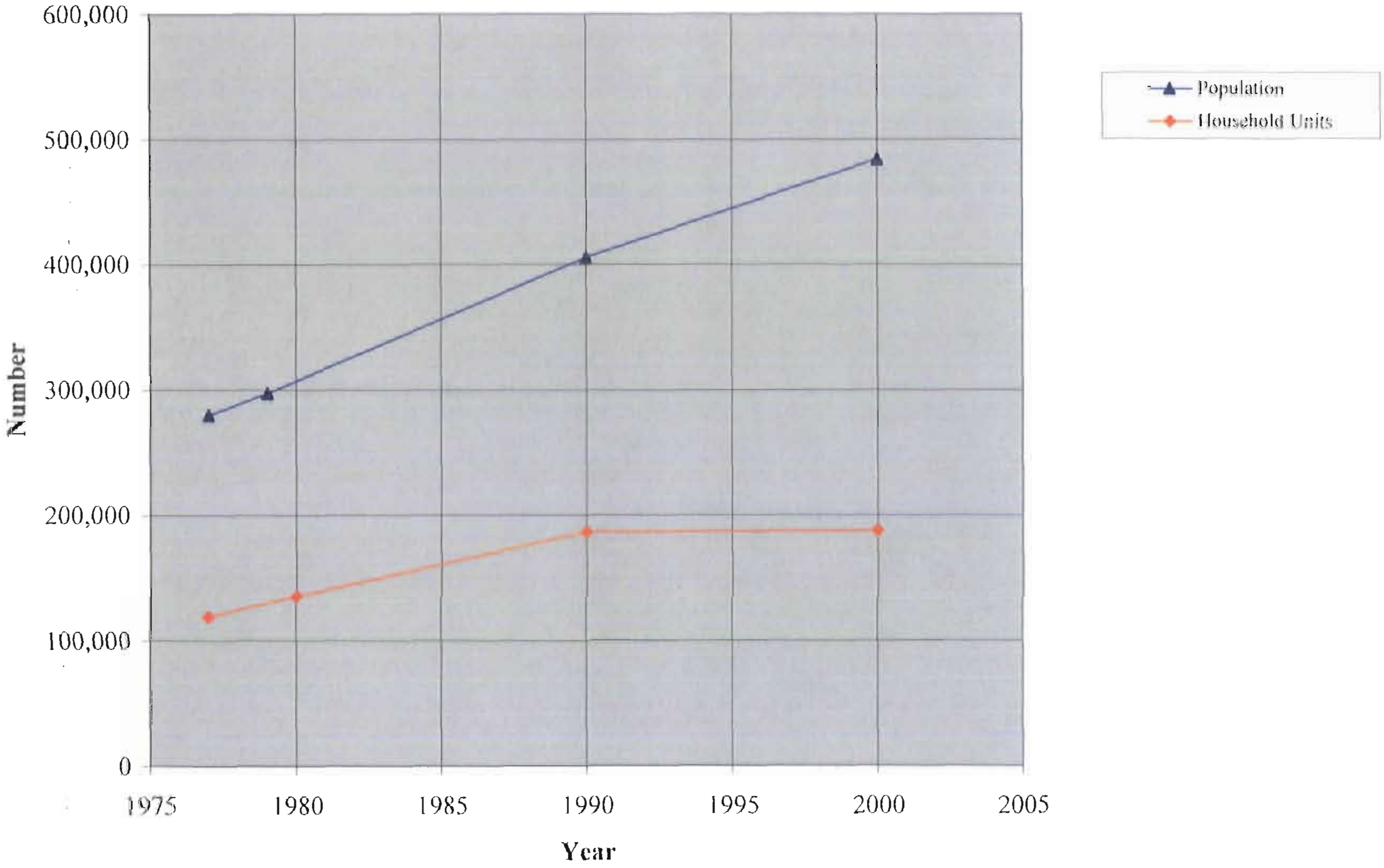

Plant Island
Site Boundary
5 Miles from Boundary

SOURCE: SOUTHWEST FLORIDA WATER MANAGEMENT DISTRACT 1999 LAND USE

Florida Power
Hines Energy Complex

FIGURE 2.2.3-2
EXISTING LAND USE WITHIN
5 MILES OF THE PLANT

**Figure 1. Population and Household Unit Trends in Polk County**



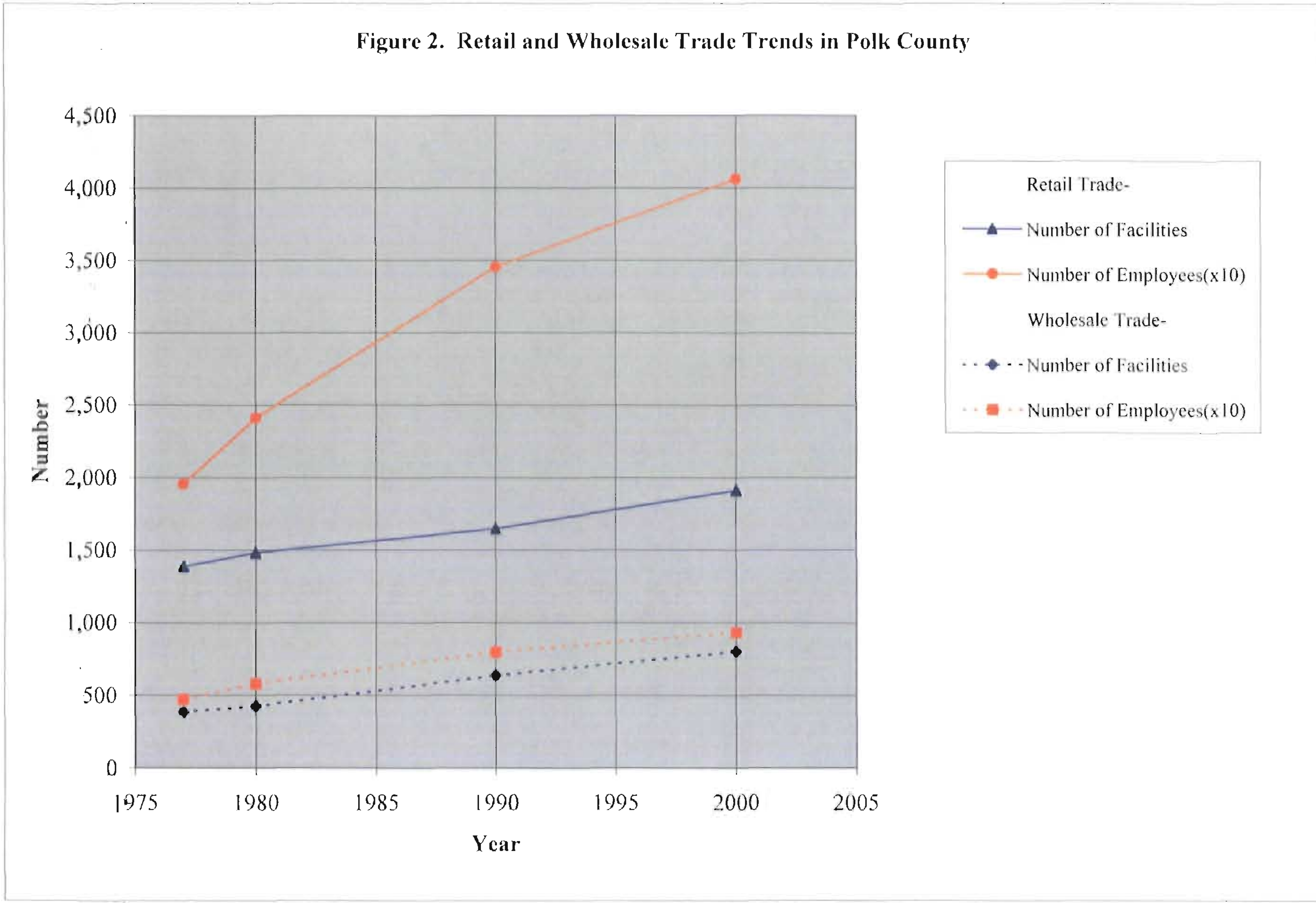


Figure 2. Retail and Wholesale Trade Trends in Polk County
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Number
1975
1980
1985
1990
1995
2000
2005
Year
Retail Trade-
Number of Facilities
Number of Employees(x10)
Wholesale Trade-
Number of Facilities
Number of Employees(x10)

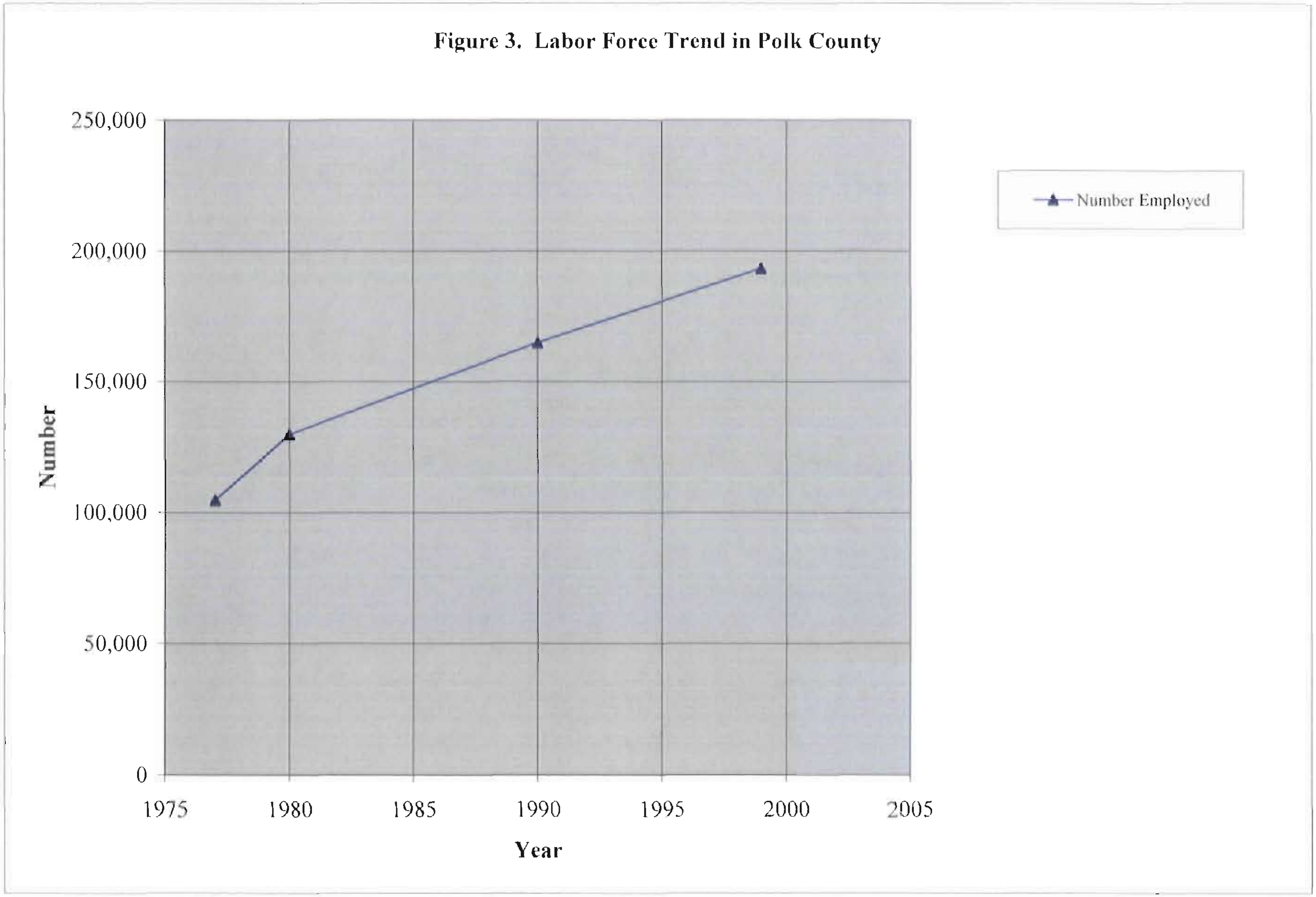


Figure 3. Labor Force Trend in Polk County
250,000
200,000
150,000
100,000
50,000
0
Number
1975
1980
1985
1990
1995
2000
2005
Year
Number Employed

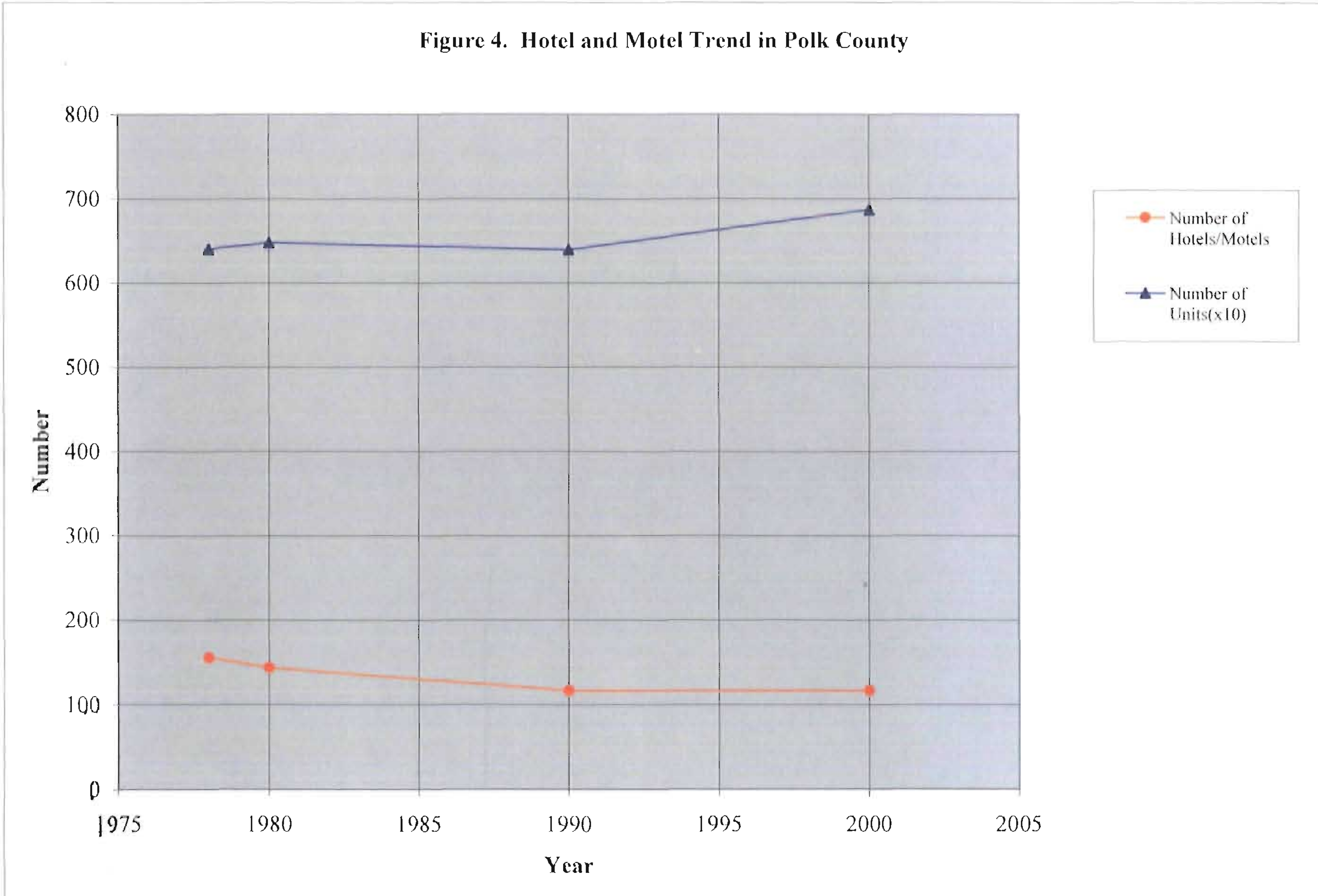


Figure 4. Hotel and Motel Trend in Polk County
800
700
600
500
400
300
200
100
0
Number
1975
1980
1985
1990
1995
2000
2005
Year
Number of Hotels/Motels
Number of Units(x10)

**Figure 5. Vehicle Miles Traveled (VMT) Estimates for Motor Vehicles for Polk County**

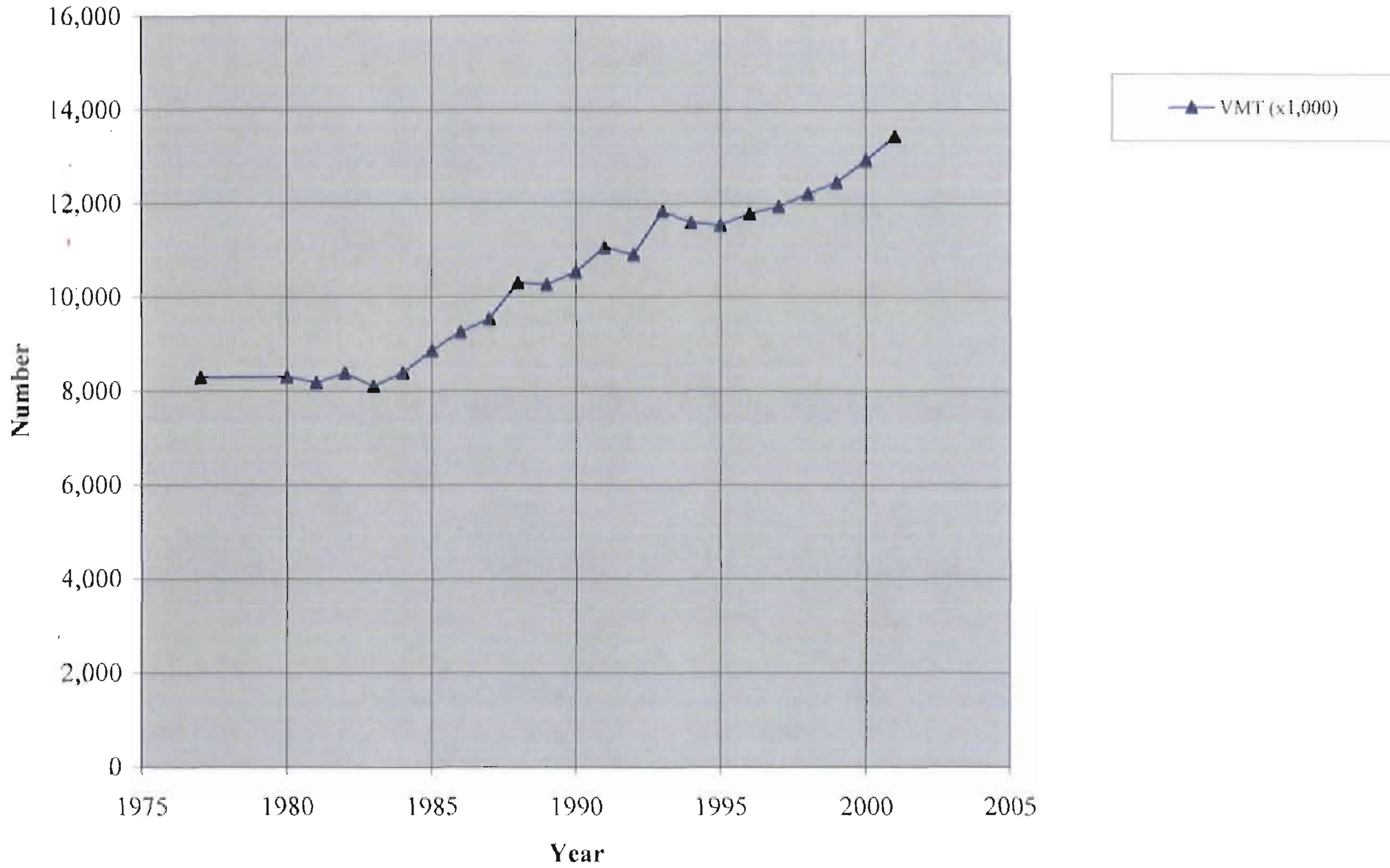


Figure 6. Electrical Power Generation Capacity in Polk County

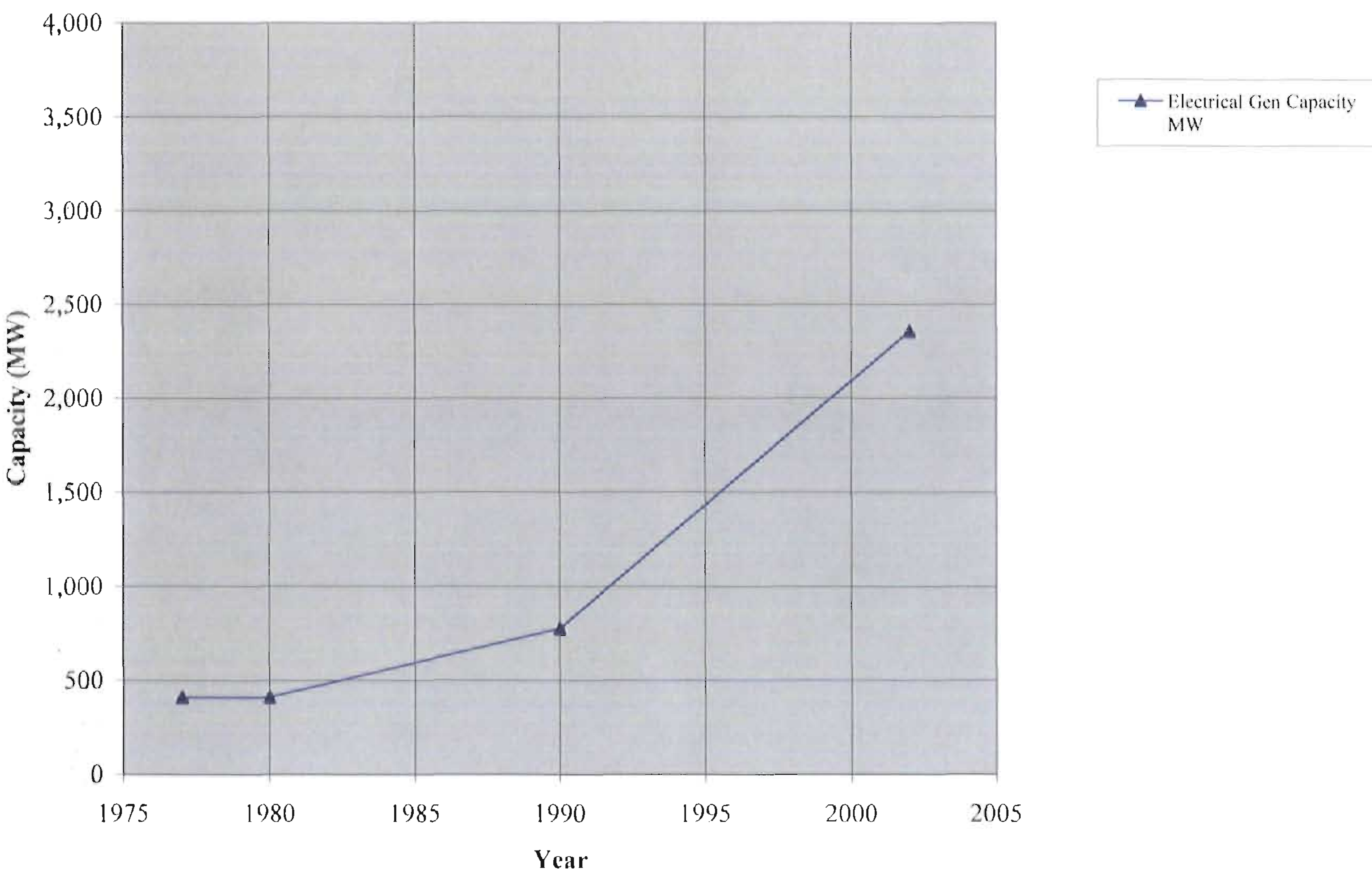


**Figure 7. Mining, Manufacturing, and Citrus Industry Trends in Polk County**

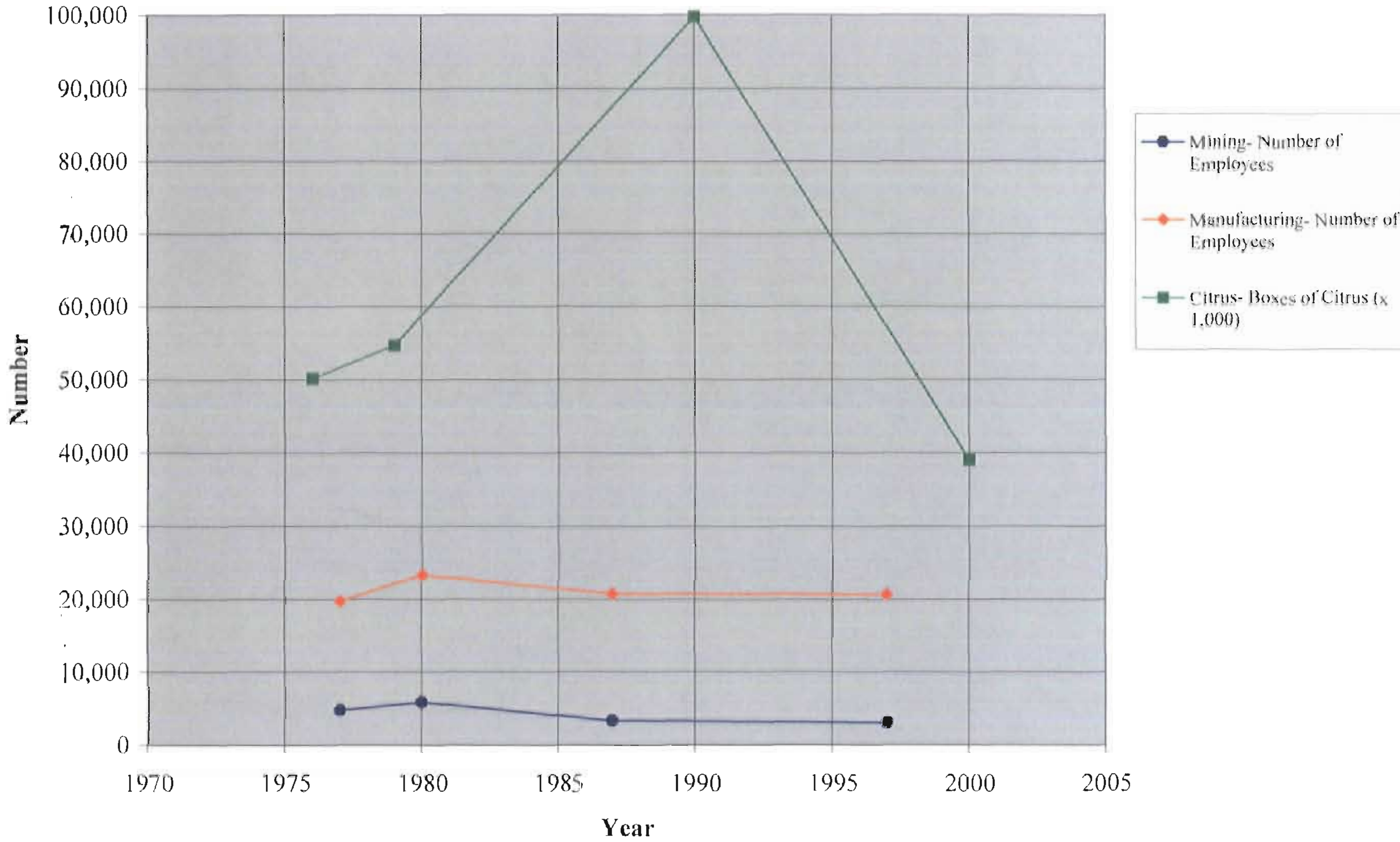


**Figure 8. Major Sources of Air Emissions in Polk County**

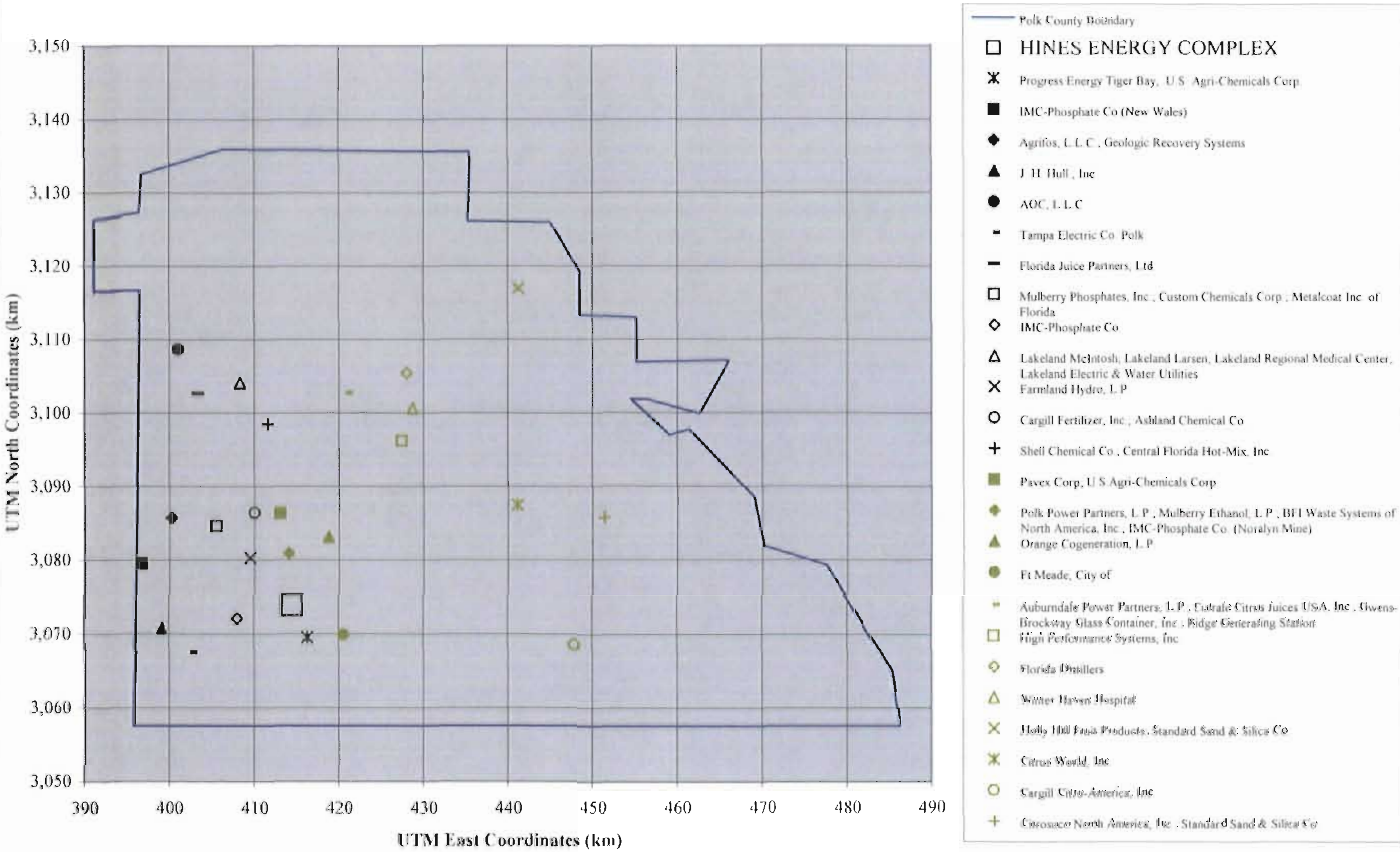


**Figure 9. Mobile Source Emissions (Tons per Day) of CO, VOC, and NOx in Polk County**

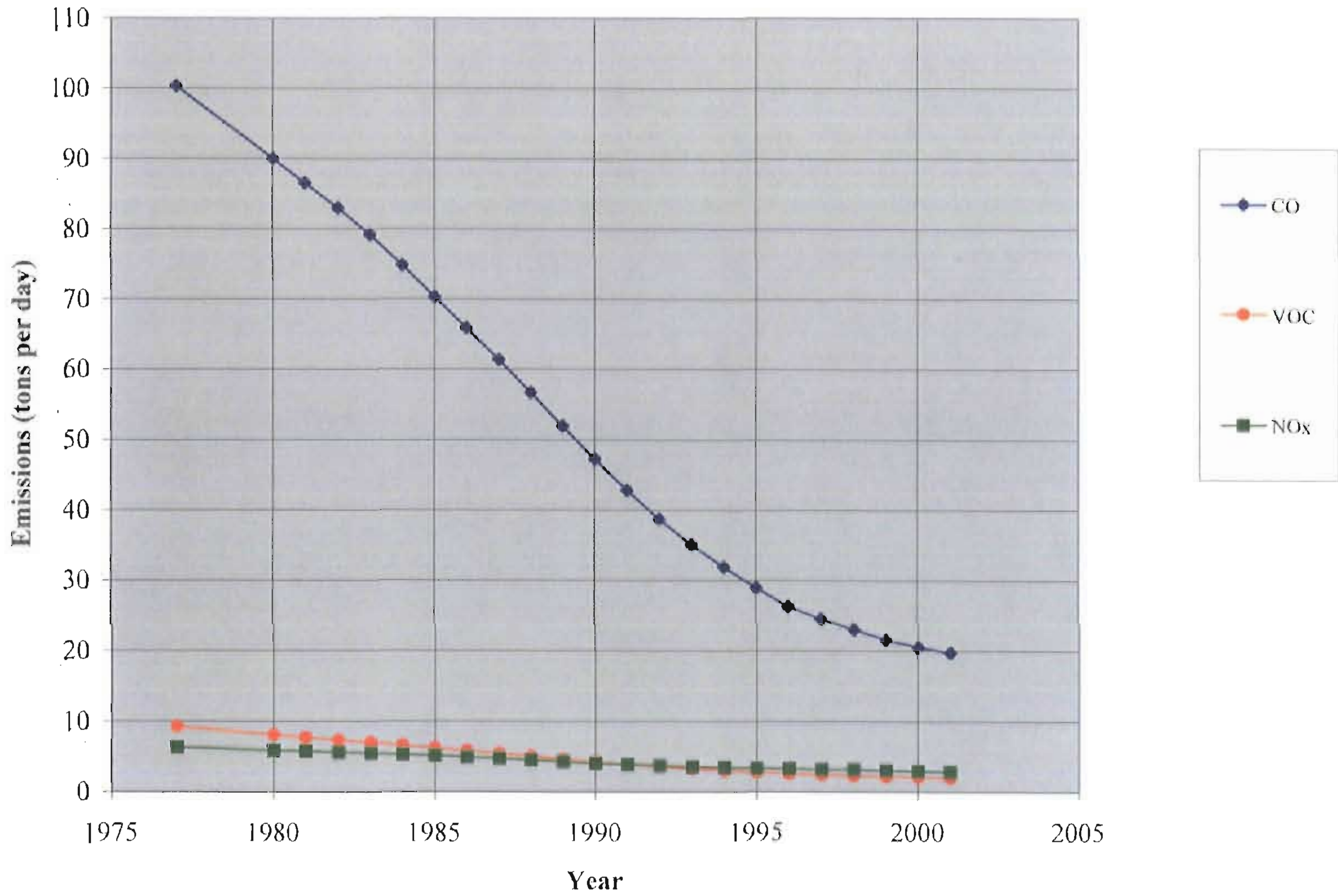
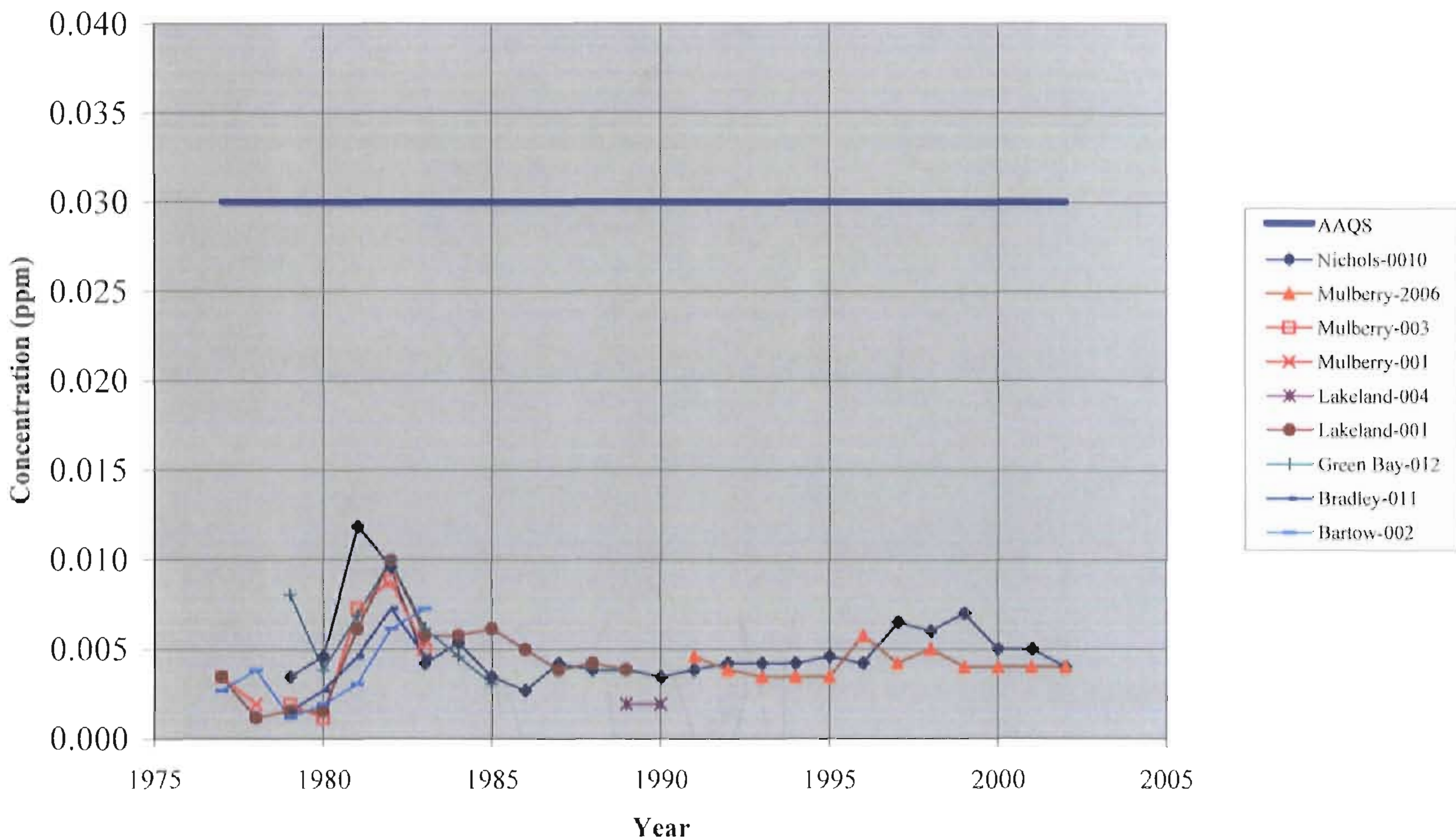


**Figure 10. Measured Annual Average Sulfur Dioxide Concentrations from 1977 to 2002- Polk County**



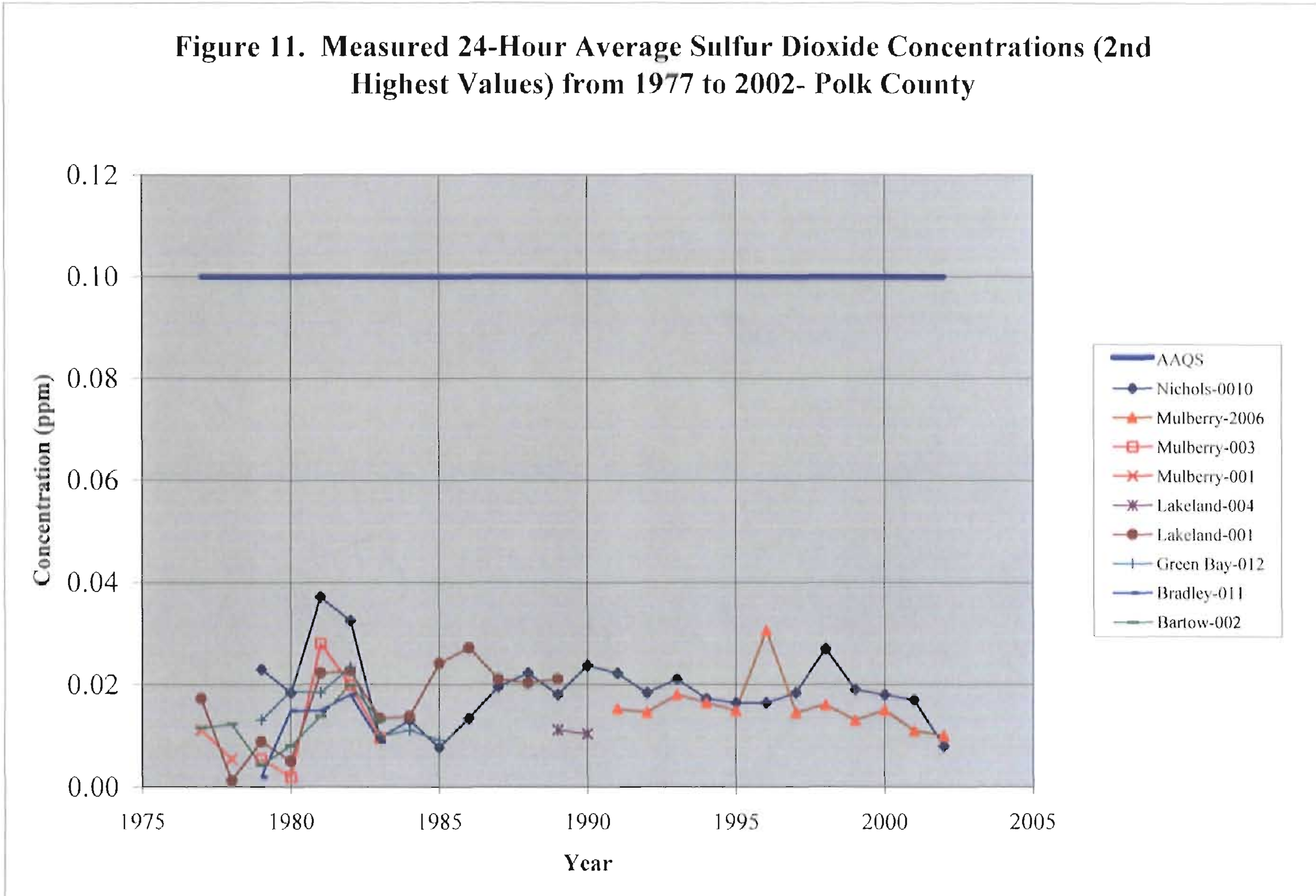
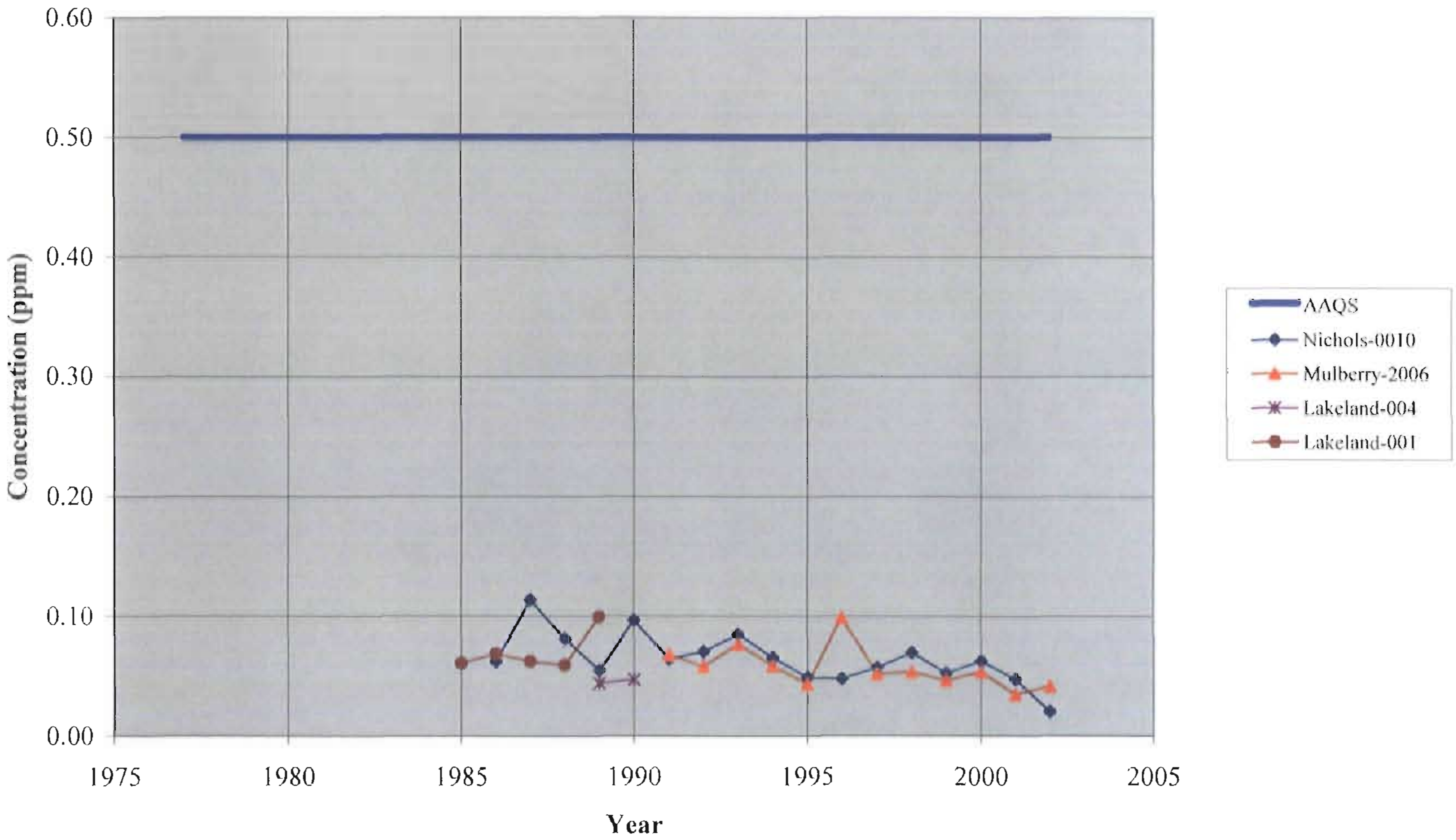
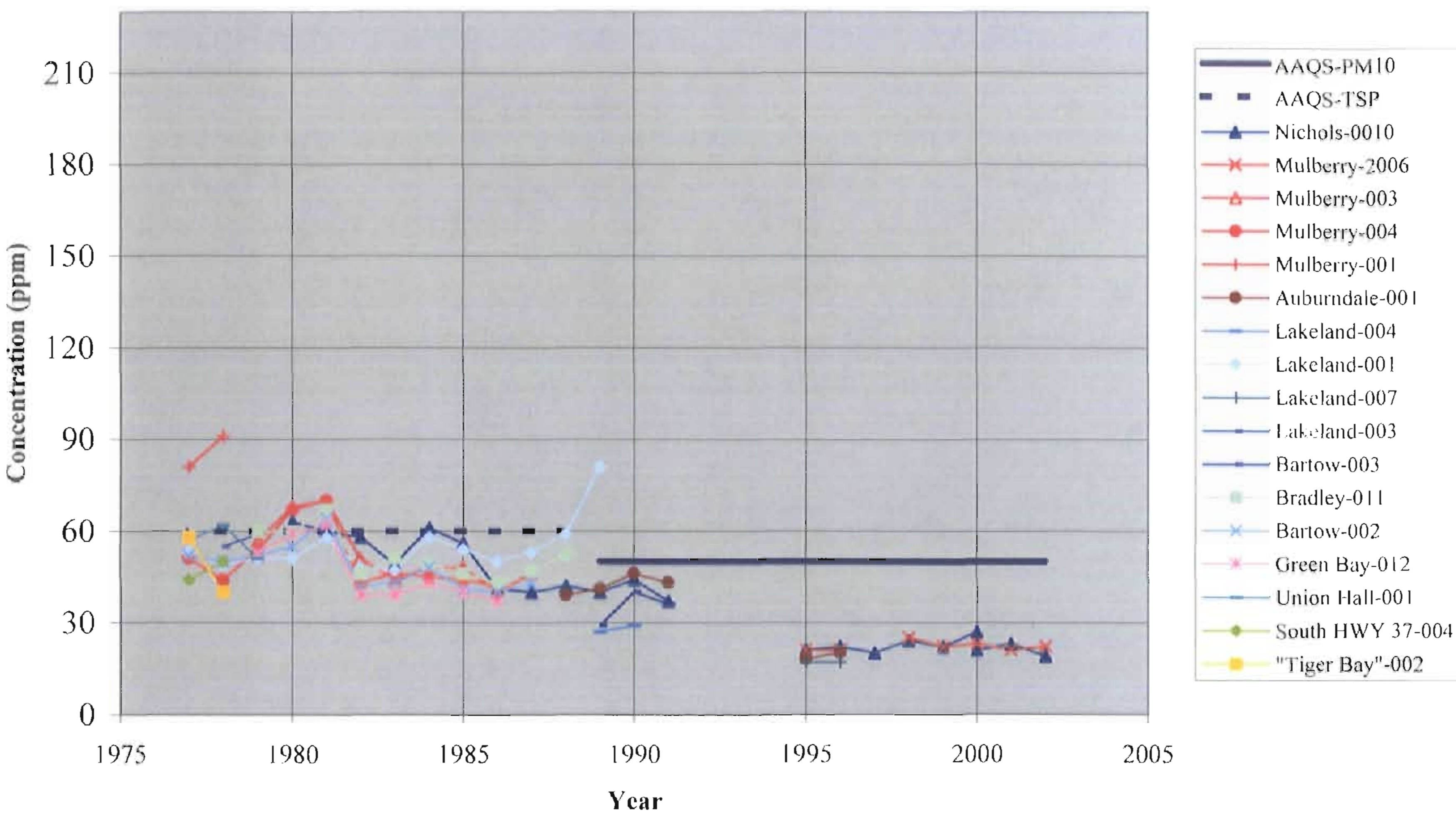


Figure 11. Measured 24-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Polk County
Concentration (ppm)
0.12
0.10
0.08
0.06
0.04
0.02
0.00
1975
1980
1985
1990
1995
2000
2005
Year
AAQS
Nichols-0010
Mulberry-2006
Mulberry-003
Mulberry-001
Lakeland-004
Lakeland-001
Green Bay-012
Bradley-011
Bartow-002

**Figure 12. Measured 3-Hour Average Sulfur Dioxide Concentrations (2nd Highest Values) from 1977 to 2002- Polk County**



# Figure 13. Measured Annual Average PM10 Concentrations (1988 to 2002) and Total Suspended Particulate Concentrations (1977 to 1987) - Polk County



# Figure 14. Measured 24-Hour Average PM10 Concentrations (1988 to 2002) and Total Suspended Particulate Concentrations (1977 to 1987) (2nd Highest Values) - Polk County

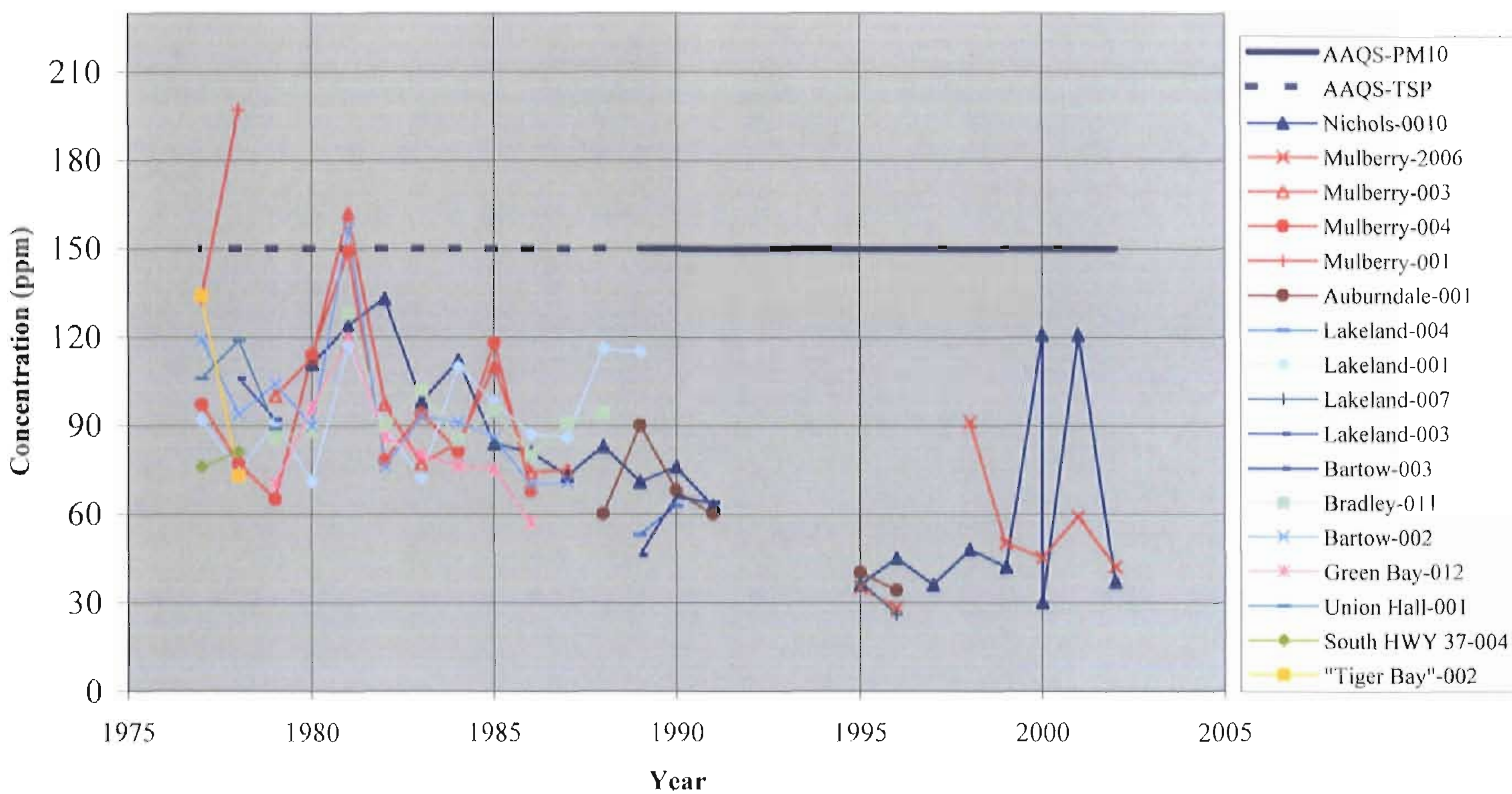


Figure 15. Measured 1-Hour Average Ozone Concentrations (2nd Highest Values) from 1977 to 2002- Polk County

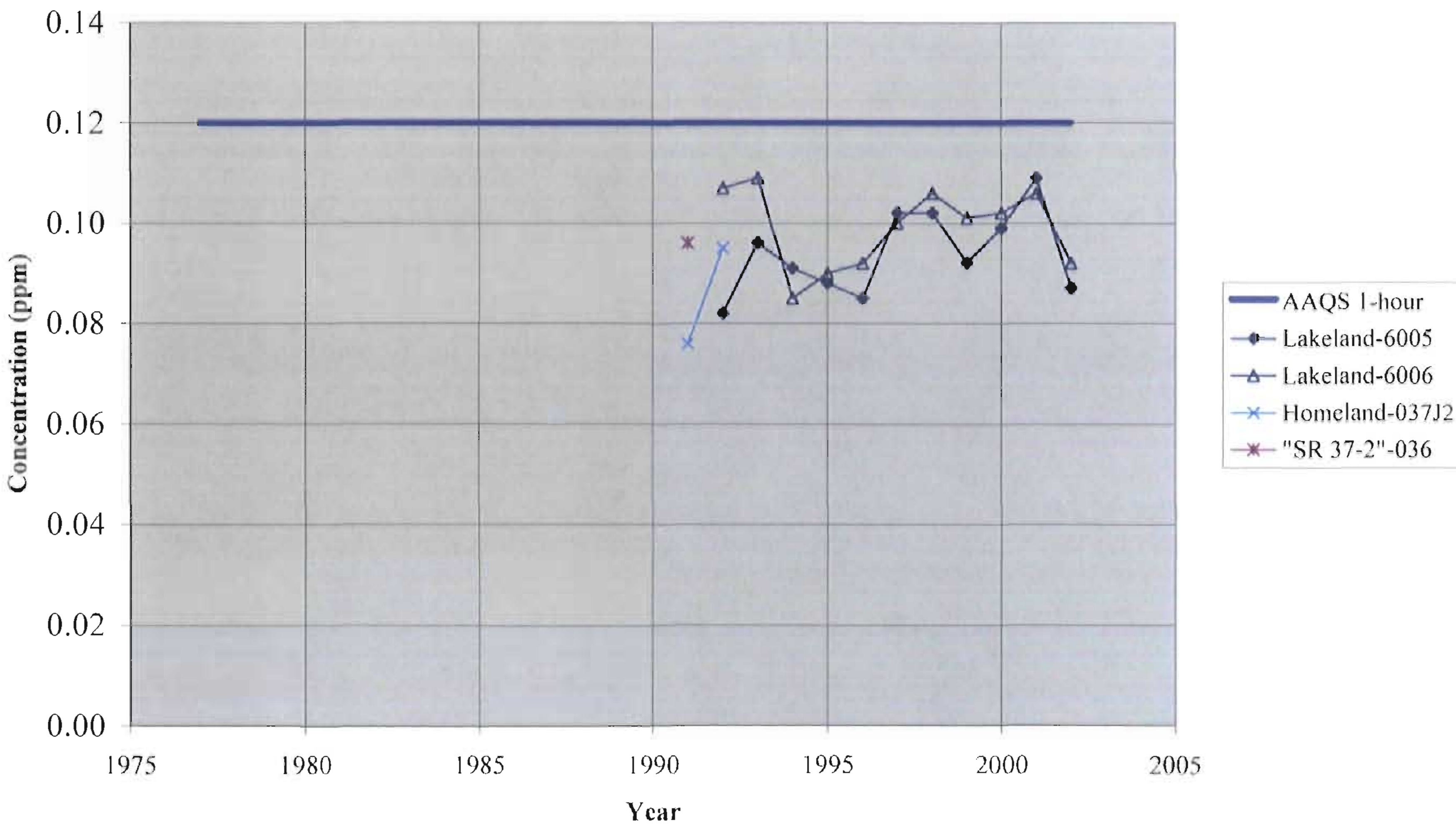
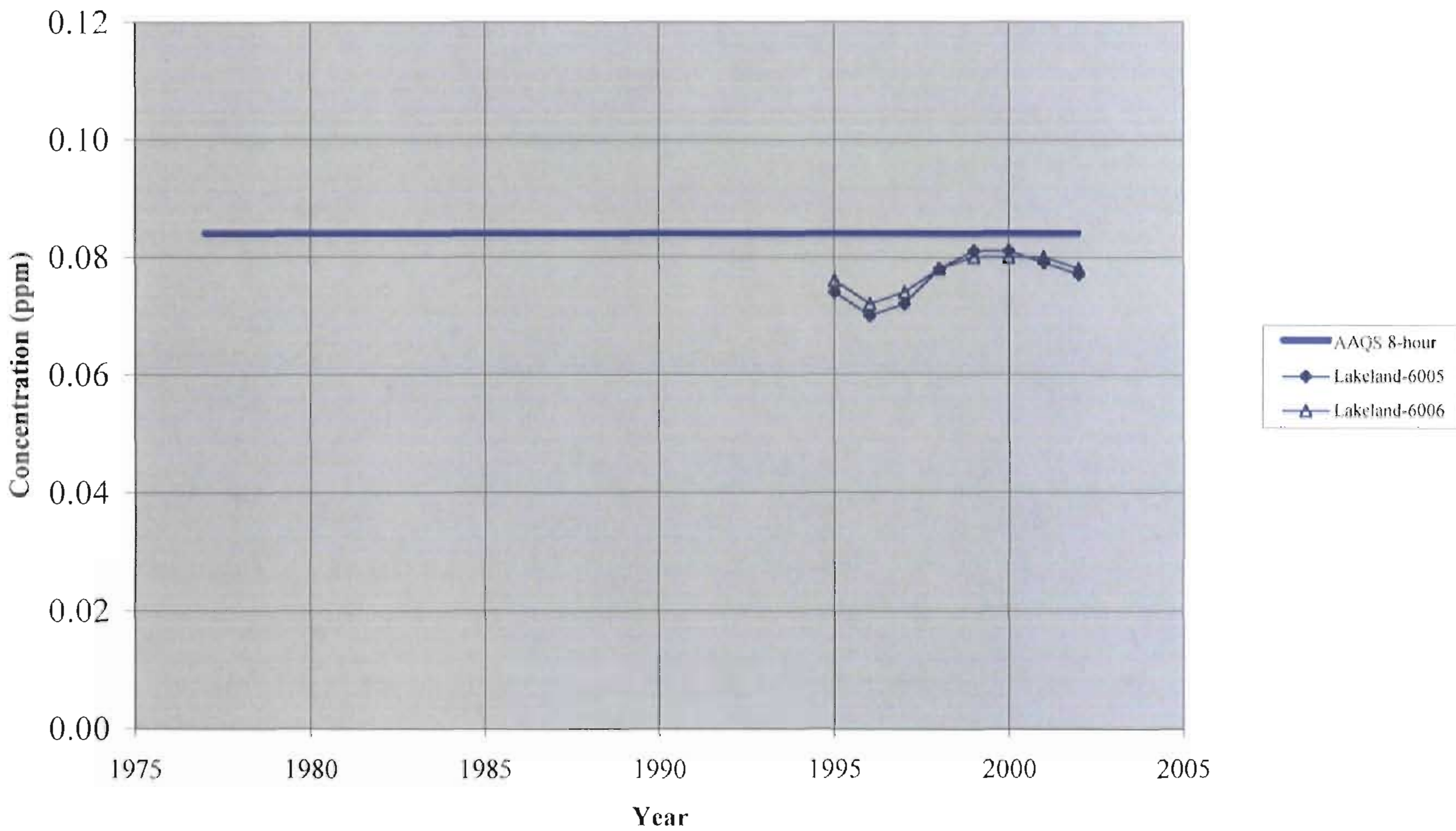


**Figure 16. Measured 8-Hour Average Ozone Concentrations (3-Year Average of the 4th Highest Values) from 1995 to 2002- Polk County**



TO: Hamilton B. Oven
Power Plant Siting Coordinator

THROUGH: Al Linero
Bureau of Air Regulation

FROM: Greg DeAngelo
Deborah Galbraith
Bureau of Air Regulation

DATE: October 4, 2002

SUBJECT: Florida Power Corporation (FPC) Hines Energy Complex Power Block 3
DEP File 1050234-006-AC (PSD-FL-330)

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The following information is needed in order to continue processing this application:

**CARBON MONOXIDE**

1. BACT for Carbon Monoxide (CO): For CO, the Prevention of Significant Deterioration (PSD) application proposes a Best Available Control Technology (BACT) emission limit of 16 ppmvd corrected to 15-percent oxygen ($O_2$) when firing natural gas in the Siemens Westinghouse 501 FD combustion turbines. The application forms, however, propose an emission limit of 10 ppmvd corrected to 15-percent $O_2$. Explain the discrepancy and confirm not only which emission limit is proposed as BACT but also which emission limit was used in the economic analyses.

   The application forms also propose an alternative limit of 50 ppmvd corrected to 15-percent $O_2$ when the combustion turbine is operating at 60 percent load. The PSD application does not address this alternative emission limit. Provide justification for setting an alternative limit at low load operation. Is the 50 ppmvd limit proposed for operation from 0 to 60 percent load?

   Other states, including New York, Massachusetts, New Jersey, Arizona, Connecticut, Washington, and California have enforced BACT standards by permitting a large number of gas-fired combined and simple cycle power plants with CO limits of 2 to 6 ppmvd at 15 percent $O_2$, averaged over 3 hours and achieved using an oxidation catalyst. Continuous compliance is demonstrated using CEMS, based on 3-hour averages. Please comment.

2. Startup and Operation at Low Loads: The application presents predicted CO performance at load levels of 60, 80, and 100 percent (65 percent instead of 60 percent for fuel oil firing). Based on manufacturer data, emissions testing at Power Block 2, and data collected during testing and operation of Power Block 1, how does the combustion turbine perform at loads less than 60 percent with respect to CO emissions? How long would a startup period last? Why is a 60 percent load assumed for the low-end of natural gas "normal operation" while 65 percent is used for fuel oil?

3. Continuous Emission Monitoring System (CEMS): Continuous compliance with CO emission limits through the use of a CEMS has been determined to be BACT in recent Department actions for similar projects. Please comment on the feasibility of operating a CO CEMS.

4. CO Catalyst Costs: The application presents direct, indirect, and annualized capital costs for an oxidation catalyst to control CO on a General Electric 7FA combustion turbine operating in combined cycle mode. (Reference is Appendix B, Tables B-8 through B-11.) Explain why these cost calculations are appropriate for the Siemens Westinghouse 501 FD combustion turbine.

On the BACT economic analysis, what is the basis (e.g., vendor's quote, capital recovery data) of the values given for the oxidation catalyst? Provide the names of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project. Total proposed annualized cost per unit of $700,340 appears to be higher than annualized cost for recent combined cycle projects reviewed by the Department (Cana at $355,941 and El Paso at $485,927). The cost effectiveness is also lower for those projects (Cana at $2,852/ton and El Paso at $2,475/ton) compared to the proposed cost of $3,773 for this project. Please comment, and recalculate the CO economic analysis as necessary.

5. Carbon Dioxide ($CO_2$) Emissions Increase or Decrease: What would be the overall $CO_2$ increase or decrease in emissions for the facility as a result of applying the oxidation catalyst technology in the new units? The application states that "the end result is an additional 2,030 tons/year of [$CO_2$]." Please submit an explanation of this statement, comparing the decrease (in tons per year) of the operation of the new units with oxidation catalyst versus the increase of the operation of the older units as a result of supplying needed energy. Identify which electrical power generation units are assumed to represent the "older, less efficient technology." How much energy (MW) from these new units will replace energy from the older, less efficient units? (Reference is PSD Application, page 4.3-10.)

**NITROGEN OXIDES**

6. BACT for Nitrogen Oxides ($NO_X$): Other states, including New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California have enforced BACT standards by permitting a large number of gas-fired combined cycle power plants with $NO_X$ limits of 1.55 to 2.5 ppmvd corrected to 15 percent $O_2$, averaged over 1-hour, and achieved using selective catalytic reduction (SCR). Florida has recently issued BACT limits of 2.5 ppmvd corrected to 15 percent $O_2$ for several General Electric 7FA combined cycle combustion turbines. California has issued a 2.5 ppmvd limit for a Siemens Westinghouse 501 FD unit. Please comment with respect to the proposed $NO_X$ emission limit of 3.5 ppmvd corrected to 15 percent $O_2$ on a 24-hour block average.

7. Incremental Cost Calculation for SCR: The BACT recommendation is based on the incremental cost of the additional tons removed by an SCR system designed for 2.5 ppmvd versus one designed for 3.5 ppmvd. Explain how a top-down approach to BACT determination would reject SCR at 2.5 ppmvd (at a cost effectiveness of $2770/ton) in favor of the next best technology, SCR at 3.5 ppmvd (at a cost effectiveness of $2741/ton). (Reference is PSD Application, page 4.3-7.)

**OTHER POLLUTANTS**

8. Volatile Organic Compounds (VOC): Similar to the proposed BACT for CO, the PSD application and the application forms contain different proposed VOC emission limits for the combustion turbines when firing natural gas. The forms propose 1.8 ppmvd corrected to 15 percent $O_2$, while the application references 2.0 ppmvd. Confirm which limit is proposed as BACT and which limit was the basis for the emissions and control cost calculations.

   Likewise, provide a justification for setting an alternative limit at low load operation. Is the 3.0 ppmvd limit proposed for operation from 0 to 60 percent load?

9. Sulfur Dioxide ($SO_2$): The PSD application bases $SO_2$ emissions on the sulfur content of the natural gas. Table 2-4, Typical Natural Gas Analysis, presents a maximum total sulfur number of 1 grain per hundred standard cubic feet (1 grain/100 SCF). The source for this data is Florida Gas Transmission. Is this sulfur content contractually guaranteed from the natural gas supplier? Please explain. (Reference is PSD Application, page 2.2-6.)

**OTHER QUESTIONS**

10. Minor Sources: The application only lists the combustion turbines, heat recovery steam generators, and the steam turbine. What will be the auxiliary equipment for this project (e.g., cooling tower, fire pump)? Submit emissions estimates for these minor sources, and include these emissions as part of the PSD applicability review.

11. Automated Control System: What type of control system (e.g. Mark V control system) is recommended by the combustion manufacturer?

12. Start Up and Shutdown Emissions: Please submit a Best Operating Practice procedure for minimizing emissions during start up and shutdown (cold, warm, and hot). What is the proposed number of startup/shutdowns per year? Estimate the pollutants emissions during this period. Please provide supporting documentation.

13. Maximum Achievable Control Technology for HAPS: Do the proposed emissions rates for these pollutants include emissions during startup and shutdowns? Please explain.

14. BACT Social Impacts: Expand the BACT analysis to include the social impact of the application of SCR and oxidation catalyst.

15. Maximum Potential Emission Summary: For Table A-25, in Appendix A, identify the four cases labeled A through D, as footnote b appears to be missing.

**AIR QUALITY ANALYSIS**

16. Air Quality Impacts of Growth: Rule 62-212.400(3)(h)(5), Florida Administrative Code (F.A.C.), states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general, commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please satisfy this rule requirement as it relates to the Hines Power Block 3 facility or state where in the submitted application it is satisfied.

**ADDITIONAL COMMENTS**

Comments from EPA and NPS will be forwarded when received.

**ADMINISTRATIVE REQUIREMENTS AND CONTACT INFORMATION**

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature.

If there are any questions, please contact Greg DeAngelo (review engineer) at (850)921-9506 and e-mail gregory.deangelo@dep.state.fl.us. Matters regarding modeling issues should be directed to Deborah Galbraith (meteorologist) at (850)921-9537 and e-mail deborah.galbraith@dep.state.fl.us.

# Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 17, 2002

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA, Region 4
61 Forsyth Street
Atlanta, Georgia 30303

RE: Florida Power Corporation
Hines Energy Complex Power Block 3
DEP File No. 1050234-005-AC, PSD-FL-330

Dear Mr. Worley:

Enclosed for your review and comment is an application submitted by Florida Power Corporation for a PSD project at the above referenced facility in Bartow, Polk County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Greg DeAngelo, review engineer, at 850/921-9506.

Sincerely,

Patty Adams
for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Greg DeAngelo

**Department of**
# Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

September 17, 2002

Mr. John Bunyak, Chief
Policy, Planning & Permit Review Branch
NPS – Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

RE: Florida Power Corporation
Hines Energy Complex Power Block 3
DEP File No. 1050234-005-AC, PSD-FL-330

Dear Mr. Bunyak:

Enclosed for your review and comment is an application submitted by Florida Power Corporation for a PSD project at the above referenced facility in Bartow, Polk County, Florida.

Your comments may be forwarded to my attention at the letterhead address or faxed to the Bureau of Air Regulation at 850/922-6979. If you have any questions, please contact Greg DeAngelo, review engineer, at 850/921-9506.

Sincerely,

Patty Adams

for Al Linero, P.E.
Administrator
New Source Review Section

AAL/pa

Enclosure

Cc: Greg DeAngelo

Memorandum

# Florida Department of Environmental Protection

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BUREAU OF AIR REGULATION

TO: Power Plant Siting Review Committee

FROM: Buck Oven HO

DATE: September 5, 2002

SUBJECT: Florida Power Corp. Hines Energy Complex - Power Block 3
PA 92-33SB, Module 8043

The Department has received a supplemental application for certification of Power Block 3 at the FPC Hines Energy Complex in Polk County. Copies of the application will be delivered to you shortly. Please review the application for Sufficiency (completeness) and advise me by October 7, 2002. Please keep in mind that this is a supplemental application. Some information in the original application submitted as FPC Polk County Site will still be relevant. Some of the Conditions of Certification (COC) for the units of Power Blocks 1 & 2 and the site as a whole will apply. This will also be an opportunity to review the COC and to update them as may be appropriate.

If you have questions, call me at Suncom 277-2822.

cc: Tim Parker
Geof Mansfield
Joe Bakker
Richard Tedder
Al Linero
Deborah Getzoff

Florida Power
A Progress Energy Company



December 18, 2002

Mr. Hamilton Oven, P.E., Administrator
Office of Siting Coordination
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Re: **Florida Power - Hines Energy Complex**
**Power Block 3**
**Supplemental Site Certification Application - PA 92-33SA2**
**Response to Sufficiency Questions**

Dear Mr. Oven:

Please find below responses to the sufficiency items outlined in your letter dated November 7, 2002. For clarity, the items noted in the November 7th letter have been repeated, followed by the response.

<u>**FDEP Southwest District Questions**</u>

<u>WATER FACILITIES PROGRAM</u>

**Domestic Wastewater**

1. Upon review of Domestic/Sanitary Wastewater Section (Part 3.5.2), the work described in the Supplemental SCA should not change or adversely impact the existing domestic wastewater treatment plant operation.

***<u>Response:</u>***

*Florida Power agrees with this comment. No further response required.*

**Potable Water**

2. Based upon the information submitted in the Supplemental SCA, the facility does not appear to require any permits; however, the following is requested to more accurately characterize the effects on the existing potable system:

P.O. Box 14042
St. Petersburg, FL 33733

a. the number of the existing employees (per day not per shift),
b. the number of proposed employees (per day not per shift), and
c. will lines being run to the proposed facility be dedicated or does the potential exist for additional tie-ins?

***Response:***

*The number of existing employees per day is 29.*

*An additional 4-6 employees will be added due to Power Block 3.*

*A single service connection will be installed to serve the minor additional needs for Power Block 3. The extension will provide potable water for safety showers, eyewash stations, sinks and one additional single restroom.*

3. Additionally, regulatory authority for potable water in Polk County is delegated to the Polk Co. Department of Health who may have additional permitting requirements.

***Response:***

*Comment noted. No further response required.*

**Industrial Wastewater**

4. Section 3.1 of the Supplemental SCA states that Power Block 3 will not require any expansion of the Cooling Pond. It is also stated that the 722-acre portion of the ultimate 2250-acre Cooling Pond has been constructed and is sufficient to support Power Blocks 1, 2, and 3. Please request that the applicant provide, or identify within the Supplemental SCA, information regarding the expected Cooling Pond water balance impact of supporting an additional Power Block 3. Does the design of the Cooling Pond dams addressed in the 1992 SCA account for water balance impacts of operating an additional Power Block 3? Please request that the applicant, if necessary, provide dam stability and seepage analysis information for any impacts not addressed by the 1992 SCA for the design of the Cooling Pond dams.

***Response:***

*The Cooling Pond water balance information, including impacts due to Power Block 3, can be found in Section 3.5.1 of the Supplemental SCA. Since the increase in water consumption due to Power Block 3 will be equally offset by additional make-up water added to the Cooling Pond, there will be no significant impacts on the overall operation of the pond or issues related to dam stability.*

*In addition, the annual dam inspections required by the current Conditions of Certification at XVII.H.1, will continue to provide reasonable assurance that the dams are operating as designed.*

WASTE MANAGEMENT PROGRAM

**Solid Waste**

1. The current submittal indicates that there is no on-site disposal of solid waste. Upon review of the Supplemental SCA the Solid Waste Section of the Southwest District does not have any question regarding the submittal.

***Response:***

*Florida Power concurs with this statement. No further response required.*

WATERSHED MANAGEMENT PROGRAM

**Ground Water**

1. Indications in application Volumes 1 and 2 are that no change in the nature of the current on-site discharges are to occur nor does there appear to be any new discharge locations on the footprint due to Power Block 3.

***Response:***

*Florida Power concurs with this statement. No further response required.*

2. Departmental records indicate that the ground water monitoring plan (GWMP) for the facility was implemented in January of 1998, and consists of 7 wells designated IMW-1 through 6 (Intermediate aquifer), and FMW-1 (Floridan aquifer). Watershed Management requests a copy of the post construction GWMP well location map.

***Response:***

*A copy of the December 23, 1997 letter and attached map depicting the monitoring well locations is enclosed (Enclosure 1). In addition, the March 16, 1998 cover letter for the well completion reports is enclosed for reference.*

**Surface Water**

3. The applicant is requesting that the Department recognize Supplemental Certification of the operation of an additional 530 MW nominal gas fired combined cycle unit at its existing Hines Energy Complex. The submittal describes the facility as a zero discharger though it states in the application that: "Tiger Bay receives water input from direct precipitation, groundwater seepage through the cooling pond southern dam and minimally from adjacent upland areas."

On October 11, 2001, Jeff Hilton of the DEP Southwest District Industrial Wastewater Compliance and Enforcement conducted an inspection of the facility and in an interoffice memo dated November 14, 2001, described the seepage from the cooling ponds as "The toe areas of the south dams of the cooling pond N-16 and CSA N-16C have approximately 44 sand drains spaced at 200-foot intervals. The drain outlets were in good condition and were clear of vegetation." In order to evaluate the potential surface water quality impacts on Tiger Bay related to the toe drains, Watershed Management recommends submittal of water quality data as described below.

Watershed Management requests the facility provide the Department with water quality data collected at the cooling pond near the sand drains, in Tiger Bay near the sand drains and at a site in Tiger Bay outside of the influence of the sand drains. The facility should provide a plan of study (POS) that includes the location of the sampling sites and a quality assurance project plan (QAPP). The sampling events shall begin upon receiving written approval from the Department. The sampling sites shall be sampled on at least three separate occasions and one sampling event should occur during the wet season. Upon completion of the three sampling events the facility shall submit to the Department a report that discusses the results of the three sampling events and includes the raw data and chain of custody sheets. This data should be requested in both printed and electronic formats and should include a summary and interpretation of the data.

The following *in-situ* parameters should be measured at every site during each separate sampling event: dissolved oxygen, specific conductance, pH, and temperature. Grab samples should be collected at the site and analyzed for the following parameters: nutrients (total nitrogen, total ammonia, total Kjeldahl nitrogen, nitrite-nitrate and orthophosphate), chlorophyll *a* and phaeophyton, fecal and total coliform bacteria, base/neutrals and acid extractables (BNAs), oil and grease, total recoverable petroleum hydrocarbons (TRPH), hydrogen sulfide, sulfate, metals (aluminum, arsenic, boron, cadmium, chromium, copper, iron, lead, magnesium, manganese, mercury, nickel, silver, thallium, vanadium and zinc), volatile organic carbons (VOCs), turbidity, total suspended solids (TSS), and $BOD_5$. Flows shall be measured at sites near the sand drains and the ambient site during each sampling event.

***Response:***

*The request above appears to be better suited as a proposed Condition of Certification for this project rather than a sufficiency request. The information requested requires a timeframe that exceeds the ability to comply with the Supplemental SCA processing schedule.*

*Florida Power also questions the validity and purpose of the above requested sampling program. Florida Power's water quality compliance requirements are set forth in the existing Conditions of Section XVIII (Groundwater) of the 1992 Site Certification. These conditions have required Florida Power to install monitoring wells at the southern boundary of the Zone of Discharge of the Cooling Pond and to monitor these wells quarterly. This quarterly monitoring has demonstrated that discharges from the Cooling Pond are in compliance with applicable GII Groundwater (i.e. Primary & Secondary Drinking Water) Standards. Additionally, these conditions require Florida Power to perform a wastestream characterization of the Cooling*

*Pond within six months after startup of each successive power block for the purpose of determining the adequacy of the applicable groundwater monitoring parameters.*

*It should be noted that the sand drains along the southern dam of the Cooling Pond were required by the Department and SWFWMD as a hydrologic enhancement to the Tiger Bay watershed. No surfacewater monitoring program was required by the Department as a condition of approval of the Cooling Pond design plans. The conditions of the 1992 Site Certification established Groundwater monitoring as the appropriate method of demonstrating that seepage from the Cooling Pond is in compliance with applicable standards and these conditions were not modified by the Department during the 2001 PB2 Supplemental Certification proceedings. The addition of Power Block 3 at Hines is expected to have no significant impact on the water quality of the Cooling Pond. Therefore, Florida Power intends to perform the wastestream characterizations and groundwater monitoring currently required by the Conditions of Certification.*

**FDEP Bureau of Air Regulation Questions**

The following information is needed in order to continue processing this application:

**CARBON MONOXIDE**

1. <u>BACT for Carbon Monoxide (CO)</u>: For CO, the Prevention of Significant Deterioration (PSD) application proposes a Best Available Control Technology (BACT) emission limit of 16 ppmvd corrected to 15-percent oxygen ($O_2$) when firing natural gas in the Siemens Westinghouse 501 FD combustion turbines. The application forms, however, propose an emission limit of 10 ppmvd corrected to 15-percent $O_2$. Explain the discrepancy and confirm not only which emission limit is proposed as BACT but also which emission limit was used in the economic analyses.

   The application forms also propose an alternative limit of 50 ppmvd corrected to 15-percent $O_2$ when the combustion turbine is operating at 60 percent load. The PSD application does not address this alternative emission limit. Provide justification for setting an alternative limit at low load operation. Is the 50 ppmvd limit proposed for operation from 0 to 60 percent load?

   Other states, including New York, Massachusetts, New Jersey, Arizona, Connecticut, Washington, and California have enforced BACT standards by permitting a large number of gas-fired combined and simple cycle power plants with CO limits of 2 to 6 ppmvd at 15 percent $O_2$, averaged over 3 hours and achieved using an oxidation catalyst. Continuous compliance is demonstrated using CEMS, based on 3-hour averages. Please comment.

***<u>Response:</u>***

*The limit for CO when firing natural gas is desired to be the same as that approved by the Department for Power Block 2 (i.e., 16 ppmvd corrected to 15 percent $O_2$ based on a 24-hour block average). The intent of the limit for Power Block 2 was to cover operation at full load (i.e., 10 ppmvd) and part load (i.e., 50 ppmvd) during the course of a day. The proposed combustion turbines for Power Block 3 are the same as those for Power Block 2 (i.e, Siemens*

*Westinghouse 501 FD). The BACT evaluation assumed operating conditions that provides conservative emission estimates enveloping conditions that may occur during actual operation. The assumption of 8,760-hours/year of operation at a conservative emission rate (i.e., 59 degree F turbine inlet temperature) provides a conservative basis for the BACT evaluation. To meet an emission limit of 16 ppmvd corrected to 15 percent $O_2$ on a 24-hour block basis, the units emissions would be 10 ppmvd for 20.5 hours and 50 ppmvd for 3.5 hours. Assuming 8,760 hours per year operation the CO emissions would be about 233 tons/year at the average turbine inlet temperature of 72 degrees F (i.e., 20 hours at 39 lb/hr, 3 hours at 135 lb/hr and 1 hour at 95 lb/hour). The BACT was based on a maximum emission of 216 tons/year (see Table 4-2 in PSD application). Using 233 tons/year and an emission rate with an oxidation catalyst of 30 tons/year the CO reduction would be 203 tons/year. The cost effectiveness using this calculation would be $3,450 per ton of CO removed ($700,340 divided by 203 tons CO reduced/year). The cost effectiveness in the BACT evaluation was $3,773 per ton per year CO removed. Again, both calculations are conservative given the assumption of 8,760 hours/year operation.*

*As noted above, the 50 ppmvd when operating at 60 percent load was contemplated within a 16 ppmvd 24-hour block average emission limit. A separate limit for low load operation is therefore not required*

*In regards to other states, New York, Massachusetts, New Jersey, Arizona, Connecticut, Washington, and California, are states that have non-attainment areas for various pollutants. As such, new "major" facilities attempting to locate within ozone non-attainment areas, are potentially subject to New Source Review (NSR) requirements for non-attainment areas. As precursor pollutants to the formation of ozone, $NO_x$ and VOC emissions are potentially subject to NSR requirements, including the installation of Lowest Achievable Emission Rate (LAER) control technology. In ozone non-attainment areas, LAER for VOC emissions from combined-cycle power facilities, which does not consider cost effectiveness, has typically been determined to be oxidation catalyst. An oxidation catalyst would be the same as that which can be implemented for CO control. The installation of an oxidation catalyst as LAER for VOC would also limit CO emissions. However, only BACT would be applicable to CO. Therefore, similar power facilities in New York, Massachusetts, New Jersey, Connecticut, and California have the requirement to install oxidation catalyst based on LAER requirements for VOC and not BACT requirements for CO. The Hines Energy Complex is located in Polk County, which is attainment for all pollutants. Therefore, Power Block 3 is subject to PSD BACT requirements and not LAER for both VOC and CO.*

2. <u>Startup and Operation at Low Loads</u>: The application presents predicted CO performance at load levels of 60, 80, and 100 percent (65 percent instead of 60 percent for fuel oil firing). Based on manufacturer data, emissions testing at Power Block 2, and data collected during testing and operation of Power Block 1, how does the combustion turbine perform at loads less than 60 percent with respect to CO emissions? How long would a startup period last? Why is a 60 percent load assumed for the low-end of natural gas "normal operation" while 65 percent is used for fuel oil?

*Response:*

*The information presented in the application is based on available vendor information. No data is currently available for Power Block 2, as this unit is still under construction. The only information available for Power Block 1 consists of full-load compliance testing. These tests show that Power Block 1 meets its compliance limit under these testing conditions. In regards to duration estimates during startup periods, please refer to the response to Comment 12 below. The 60 percent load when firing natural gas and 65 percent load when firing distillate oil are based on data provided by Siemens Westinghouse for the operation of the 501FD combustion turbine.*

3. Continuous Emission Monitoring System (CEMS): Continuous compliance with CO emission limits through the use of a CEMS has been determined to be BACT in recent Department actions for similar projects. Please comment on the feasibility of operating a CO CEMS.

*Response:*

*Provided a 24-hour block average emission limit (exclusive of excess emissions due to startup, shutdown and malfunction as authorized by the Department) is established for CO emissions, the use of a CO CEMS would be acceptable as the compliance demonstration method.*

4. CO Catalyst Costs: The application presents direct, indirect, and annualized capital costs for an oxidation catalyst to control CO on a General Electric 7FA combustion turbine operating in combined cycle mode. (Reference is Appendix B, Tables B-8 through B-11.) Explain why these cost calculations are appropriate for the Siemens Westinghouse 501 FD combustion turbine.

   On the BACT economic analysis, what is the basis (e.g., vendor's quote, capital recovery data) of the values given for the oxidation catalyst? Provide the names of all manufacturers that were contacted along with their estimates while developing capital and annualized cost estimates for this project. Total proposed annualized cost per unit of $700,340 appears to be higher than annualized cost for recent combined cycle projects reviewed by the Department (Cana at $355,941 and El Paso at $485,927). The cost effectiveness is also lower for those projects (Cana at $2,852/ton and El Paso at $2,475/ton) compared to the proposed cost of $3,773 for this project. Please comment, and recalculate the CO economic analysis as necessary.

*Response:*

*Appendix B, Tables B-8 through B-11, present direct, indirect, and annualized capital costs for an oxidation catalyst to control CO on a Siemens Westinghouse 501F combustion turbine. The reference to GE was inadvertent. These cost estimates are based on a vendor estimate using specific information on this specific combustion turbine.*

*The CO BACT analysis of oxidation catalyst is based on vendor quotes from Engelhard using procedures from the EPA Cost Control Manual. The cost effectiveness for Power Block 3 was estimated at \$3,773 per ton of CO removed. The cost quotes received from Engelhard and used in developing the supporting BACT analysis can be found in Enclosure 2 of this document. The capital costs were estimated using the procedures in the EPA Cost Control Manual. The direct annual and energy costs were developed from vendor and engineering estimates. The result was an annualized cost of \$700,340. Cost for other projects may be different based on the scope of each project. With regard to the Cana Project (i.e., CPV Cana Ltd.) the Department did not require an oxidation catalyst at a cost effectiveness of \$2,852 per ton removed. In addition, the Department did not propose an oxidation catalyst for the El Paso Projects with a cost effectiveness of \$2,475 per ton of CO removed. For projects using the F Class combustion turbines, the Department has not determined that oxidation catalysts are BACT. The conclusions reached by the Department in these permitting reviews, clearly suggest that an oxidation catalyst would not be appropriate for the Hines Power Block 3 project.*

5. <u>Carbon Dioxide ($CO_2$) Emissions Increase or Decrease</u>: What would be the overall $CO_2$ increase or decrease in emissions for the facility as a result of applying the oxidation catalyst technology in the new units? The application states that "the end result is an additional 2,030 tons/year of [$CO_2$]." Please submit an explanation of this statement, comparing the decrease (in tons per year) of the operation of the new units with oxidation catalyst versus the increase of the operation of the older units as a result of supplying needed energy. Identify which electrical power generation units are assumed to represent the "older, less efficient technology." How much energy (MW) from these new units will replace energy from the older, less efficient units? (Reference is PSD Application, page 4.3-10.)

***<u>Response:</u>***

*The increases and decreases for installing an oxidation catalyst are presented in Table B-11 of the Air Permit/PSD Application. The CO from each unit was calculated to decrease by 185.6 tons per year (TPY) from the emission rates guaranteed by Siemens Westinghouse. As discussed, in Section 4, page 4.3-11, the actual decrease resulting from the addition of an oxidation catalyst is not expected to be that beneficial given the actual performance of the 501F turbine. As shown in Table B-11, the backpressure on the turbine results in a direct loss of electric power that would otherwise be placed on the electric grid. The amount of power lost as a result of the backpressure is about 3 million KW-hr per year. To replace this power, other less efficient units are operated within the electric system, since electric power is being supplied to meet demand. The demand is independent of the unit operation and any energy lost within the operation of the units cannot be used to meet the demand. To meet demand, the older less efficient power units are operated. This will result in the generation of secondary air pollutants by these units even if the increment of power needed is small. For example, units that cycle would be operated at an incrementally higher load to supply the power lost. To convert the lost energy into thermal energy requirements, a heat rate of 10,300 Btu/kW-hr was used. The energy requirement was 32,062 MMBtu/year (i.e., 3,112,815 kW-hr x 10,300 Btu/kW-hr x MM/$10^6$ = 32,062 MMBtu/hr). The secondary air pollutants were estimated to be about 4 TPY of criteria pollutants and 2,030 TPY of carbon dioxide. As discussed on page 4.3-10, the amount of $CO_2$ produced as a direct result of the lost energy is more than 10 times higher than the amount of CO theoretically* *reduced (i.e., 185.6 TPY) and converted to $CO_2$ in the oxidation catalyst. While it is certain that energy lost that is not available to meet demand must be replaced, it is uncertain the exact type of unit that would replace the lost energy. Typically these are cycling units much lower on the dispatch order than Hines Power Block 3. It was assumed that the lost power would be replaced using a natural gas fired unit.*

*Power Block 3 is being built to serve the growing energy and capacity needs of Florida Power's customers both old and new. It is not being built for the purpose of displacing energy from existing units. However, under certain scenarios, the operation of the Power Block 3 will have the effect of displacing energy from such units. The actual amount of energy that Power Block 3 will displace from other, existing units will vary from year-to-year based on a number of factors (fuel prices, load growth, weather, maintenance schedules, improvements to other units, etc).*

**NITROGEN OXIDES**

6. <u>BACT for Nitrogen Oxides ($NO_X$)</u>: Other states, including New York, Connecticut, Massachusetts, Rhode Island, New Jersey, Arizona, Washington and California have enforced BACT standards by permitting a large number of gas-fired combined cycle power plants with $NO_X$ limits of 1.55 to 2.5 ppmvd corrected to 15 percent $O_2$, averaged over 1-hour, and achieved using selective catalytic reduction (SCR). Florida has recently issued BACT limits of 2.5 ppmvd corrected to 15 percent $O_2$ for several General Electric 7FA combined cycle combustion turbines. California has issued a 2.5 ppmvd limit for a Siemens Westinghouse 501 FD unit. Please comment with respect to the proposed $NO_X$ emission limit of 3.5 ppmvd corrected to 15 percent $O_2$ on a 24-hour block average.

***<u>Response:</u>***

*As mentioned in the Response to Comment 1, the BACT determinations in many of the states mentioned are also determinations based on LAER. LAER, in addition to other requirements is based on either non-attainment status or designations for interstate NOx transport. While it is recognized that the Department established $NO_x$ emission limits of 2.5 ppmvd corrected to 15 percent $O_2$ for several projects using the General Electric 7FA, the amount of $NO_x$ reduction and control requirements proposed for Power Block 3 is much greater. For example, the proposed $NO_x$ emission rate of 3.5 ppmvd corrected to 15 percent $O_2$ for Power Block 3 represents a $NO_x$ reduction of 86 percent (i.e., 25 ppmvd-3.5ppmvd = 21.5 ppmvd; 21.5/25 = 0.86). In contrast, the $NO_x$ reduction for the General Electric 7FA from 9 ppmvd corrected to 15 percent $O_2$ to 2.5 corrected to 15 percent $O_2$ is 72.2 percent (i.e., 9 ppmvd-2.5ppmvd = 6.5 ppmvd; 6.5/9 = 0.722). This will result in greater catalyst costs as well as greater backpressure on the turbine. The proposed emission limit of 3.5 ppmvd corrected to 15 percent $O_2$ represents a turbine specific BACT emission limit.*

7. <u>Incremental Cost Calculation for SCR</u>: The BACT recommendation is based on the incremental cost of the additional tons removed by an SCR system designed for 2.5 ppmvd versus one designed for 3.5 ppmvd. Explain how a top-down approach to BACT determination would reject SCR at 2.5 ppmvd (at a cost effectiveness of $2770/ton) in favor of

the next best technology, SCR at 3.5 ppmvd (at a cost effectiveness of $2741/ton). (Reference is PSD Application, page 4.3-7.)

***Response:***

*The cost effectiveness of $2,741 per ton of $NO_x$ removed at an emission rate of 3.5 ppmvd corrected to 15 percent $O_2$ reflect the total cost effectiveness for the project at that emission limit. The cost effectiveness of $2,770 per ton of $NO_x$ removed at an emission rate of 2.5 ppmvd corrected to 15 percent $O_2$ also reflect the total cost effectiveness. The incremental cost effectiveness between 3.5 ppmvd and 2.5 ppmvd (corrected to 15 percent $O_2$) is $3,463 per ton of $NO_x$ removed and also presented on Page 4.3-7 of the PSD Application. The incremental cost effectiveness for an emission limit of 2.5 ppmvd represents a 26 percent incremental increase from an emission limit of 3.5 ppmvd yet only represents a 4 percent greater reduction in $NO_x$ control (i.e., 86 to 90 percent).*

**OTHER POLLUTANTS**

8. Volatile Organic Compounds (VOC): Similar to the proposed BACT for CO, the PSD application and the application forms contain different proposed VOC emission limits for the combustion turbines when firing natural gas. The forms propose 1.8 ppmvd corrected to 15 percent $O_2$, while the application references 2.0 ppmvd. Confirm which limit is proposed as BACT and which limit was the basis for the emissions and control cost calculations.

   Likewise, provide a justification for setting an alternative limit at low load operation. Is the 3.0 ppmvd limit proposed for operation from 0 to 60 percent load?

***Response:***

*The proposed emission limit is 1.8 ppmvd corrected to 15 percent $O_2$ (which is approximately 2.2 ppmvd uncorrected). The BACT evaluation included this emission rate as part of the evaluation. As shown on Page 4.3-12 the cost effectiveness exceeds $60,000 per ton of VOC removed at 40 percent removal and nearly $30,000 per ton of VOC removed for 90 percent removal. Low load operation for the units would follow the requirements to meet the proposed CO emission rate as discussed in the Response to Comment 1. The CO and VOC emissions are related through the combustion process and to achieve a CO limit of 16 ppmvd (corrected to 15 percent $O_2$) the unit would operate 20.5 hours at high load and 3.5 hours at low load. The cost effectiveness calculation, which was based on a VOC emission rate of 27.6 tons per year, which is based on conservative operating conditions (e.g., 8,760 hours per year operation) that would envelop actual emissions during expected operation. For compliance, single stack tests at full load are proposed, along with the CO CEMS if required. Operation at all loads, including from 0 to 60 percent, would be covered by this limit (exclusive of excess emissions due to startup, shutdown and malfunction as authorized by the Department).*

9. Sulfur Dioxide ($SO_2$): The PSD application bases $SO_2$ emissions on the sulfur content of the natural gas. Table 2-4, Typical Natural Gas Analysis, presents a maximum total sulfur number of 1 grain per hundred standard cubic feet (1 grain/100 SCF). The source for this data

is Florida Gas Transmission. Is this sulfur content contractually guaranteed from the natural gas supplier? Please explain. (Reference is PSD Application, page 2.2-6.)

***Response:***

*No, the 1 grain per hundred standard cubic feet value used to calculate SO2 emissions in the application is not contractually guaranteed. This value was selected based on historical information showing that the average sulfur content of natural gas delivered via pipeline is well below the 1 grain value used in the application to conservatively estimate emissions. The BACT determination related to SO2 emissions from natural gas should be based on the use of "natural gas delivered via pipeline" and not a specific grains of sulfur in the gas, or the term "pipeline natural gas" in order to avoid confusion with the requirements of the Acid Rain Program.*

**OTHER QUESTIONS**

10. Minor Sources: The application only lists the combustion turbines, heat recovery steam generators, and the steam turbine. What will be the auxiliary equipment for this project (e.g., cooling tower, fire pump)? Submit emissions estimates for these minor sources, and include these emissions as part of the PSD applicability review.

***Response:***

*There will be no other auxiliary equipment or minor sources of air pollution associated with the Power Block 3 project. The emission units identified in the Air Permit/PSD Application are the only emission units associated with the project. These are the two combustion turbines.*

11. Automated Control System: What type of control system (e.g. Mark V control system) is recommended by the combustion manufacturer?

***Response:***

*The Power Block 3 combustion turbines will have the Siemens TXP control system, the standard for Siemens Westinghouse 501FD2 machines.*

12. Start Up and Shutdown Emissions: Please submit a Best Operating Practice procedure for minimizing emissions during start up and shutdown (cold, warm, and hot). What is the proposed number of startup/shutdowns per year? Estimate the pollutants emissions during this period. Please provide supporting documentation.

<u>*Response:*</u>

*The submittal of a Best Operating Practice procedure is somewhat premature since several of the control systems have not yet been selected (e.g., the SCR vendor). While these procedures will be submitted as part of the Title V application, the discussion below presents a discussion of startup and shutdown.*

***Startup and Shutdown***

*The startup will vary by the equipment vendors but presented below is a typical description of the process. During all startup conditions, the speed and load of the combustion turbines (CTs) are regulated to provide conditions that would not damage the HRSGs or steam turbine. The typical conditions described below.*

1. *Cold Start – Occurs when the combined cycle unit has been shutdown for more than 48 hours. The total time for this startup condition is 6 hours. The first CT is started and held at certain levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 2-hours into the start and load is applied to the CT at about 3 hours into the start. The second CT is started about 3 to 4 hours into the start with load applied at about 4 to 5 hours into the start. At 6 hours into the start, both CTs are at a load that will comply with proposed emission limits.*
2. *Warm Start – Occurs when the combined cycle unit has been shutdown for 48 hours or less. The total time for this startup condition is about 2 hours. Similar to the cold start, the first CT is started and held at levels of heat input while the exhaust gases from the CT heat up the HRSG and produce steam for the steam turbine. The steam turbine starts load at about 1 hour into the start and load is applied to the CT shortly thereafter. The second CT is started about 1 hour into the start with load applied at about 1½ hours into the start. At two hours into the start, the first CT has reach full load with steam applied to the steam turbine. The second turbine is started in similar sequence.*

*A maximum number of startups/shutdowns cannot be proposed for the Project. The number of unit startups per year will vary depending on unit dispatching maintenance requirements, forced outages, and other system factors. The units are expected to operate as mid-load to base load units, therefore, startups and shutdowns are expected to be minimal. Typical maintenance requirements would require about one cold startup/shutdown per year.*

13. <u>Maximum Achievable Control Technology for HAPS</u>: Do the proposed emissions rates for these pollutants include emissions during startup and shutdowns? Please explain.

<u>*Response:*</u>

*The emission rates for HAPs indirectly accounted for any HAPs during startup and shutdown. Emissions of HAPs were conservatively estimated by using the following assumptions:*

- *100 percent load for all operation,*
- *8,760 hour per year operation, and*
- *Conservatively high emission factors.*

*The maximum HAPs using these assumptions were estimated to be 7.3 TPY for all HAPs and 2.0 TPY for a single HAP (see Table 2-3 in Air Permit Application). These maximum HAP emissions are considerably less than the major HAP thresholds of 25 TPY for all HAPs and 10 TPY for a single HAP.*

*As noted in the preceding response, the startup times are relatively short duration and at much lower loads than that at base load. While concentrations of some air pollutants increase, the operation at lower loads produces much less relative mass emission.*

14. BACT Social Impacts: Expand the BACT analysis to include the social impact of the application of SCR and oxidation catalyst.

***Response:***

*Although not described as "social impacts," the BACT analyses for SCR and oxidation catalyst include components of social impacts for the technology. These are describe further below:*

***Social Impacts of SCR:*** *The social impacts of SCR are incorporated within the economic and energy impacts described in the Section 4 of the Air Permit/PSD Application. From a social perspective, the use of SCR has implications of both costs and benefits. The capital cost of the SCR ($3,470,485 from Table B-3) will generate some direct economic benefits. Since SCR equipment is specialized these benefits would primarily accrue to the manufacturer, which would be located out of Florida. Installation would be at the unit and likely be limited to several weeks of labor effort. The cost for SCR is estimated to be about 0.076 cents per KW-hr, which will be passed to Florida Power's customers. (Calculation: $1,809,118/unit/year x 1 unit/272,610 kW/hr x year/8,760 hrs x 100 cents/$; refer to Table B-4). With SCR, the lost power for each CT/HRSG would be sufficient to supply about 488 residential customers. This is about 0.37 percent of the electric energy that would be supplied by each CT/HRSG. SCR equipment and systems would have to be maintained and would require about 0.6 man-years per CT/HRSG. This will generate economic benefits through payroll, which has been estimated to be about $19,000/year per CT/HRSG. Pollution control equipment, such as SCR, is tax exempted from property taxes. The use of ammonia would be supplied in state (estimated to be about $287,000 per CT/HRSG) and would generate about one trip per week for delivery. A Risk Management Plan (RMP) may be required depending upon the type and quantities of ammonia. SCR would remove about 86 percent of $NO_x$ or a potential of 660 TPY. This benefit is somewhat offset due to the emissions of ammonia, PM and secondary emissions. While the $NO_x$ reduction would not significantly reduce ground-level concentration of $NO_2$ (as compared to ambient air quality standards), the reduction of $NO_x$ would be beneficial in reducing a precursor to ozone formation.*

***Social Impacts of Oxidation Catalyst (OC):*** *The social impacts of OC are incorporated within the economic and energy impacts described in the Section 4 of the Air Permit/PSD Application. From a social perspective, the use of OC has implications of both costs and benefits. The capital* *cost of the OC ($1,644,300 from Table-B8) will generate some direct economic benefits. Since OC equipment is specialized these benefits would primarily accrue to the manufacturer, which would be located out of Florida. Installation would be at the unit and likely be limited to several weeks of labor effort. The cost for OC is estimated to be about 0.029 cents per KW-hr, which will be passed to FP's customers. (Calculation: $700,340/unit/year x 1 unit/272,610kW/hr x year/8,760 hrs x 100 cents/$; refer to Table B-9). With OC, the lost power for each CT/HRSG would be sufficient to supply about 265 residential customers. OC equipment and systems would have to be maintained and would require about 0.2 man-years per CT/HRSG. This will generate economic benefits through payroll, which has been estimated to be about $6,000/year per CT/HRSG. Pollution control equipment, such as OC, is tax exempted from property taxes. OC would remove 90 percent of CO or a potential of 184 TPY. This benefit is somewhat offset due to the emissions of PM and secondary emissions. The CO reduction would not significantly reduce ground-level concentration of CO (as compared to ambient air quality standards).*

15. Maximum Potential Emission Summary: For Table A-25, in Appendix A, identify the four cases labeled A through D, as footnote b appears to be missing.

***Response:***

*See Enclosure 3.*

AIR QUALITY ANALYSIS

16. Air Quality Impacts of Growth: Rule 62-212.400(3)(h)(5), Florida Administrative Code (F.A.C.), states that an application must include information relating to the air quality impacts of, and the nature and extent of, all general, commercial, residential, industrial and other growth which has occurred since August 7, 1977, in the area the facility or modification would affect. Please satisfy this rule requirement as it relates to the Hines Power Block 3 facility or state where in the submitted application it is satisfied.

***Response:***

*There has been minimal industrial, commercial, and residential growth within a 5-mile radius of the FP Hines Energy Complex site since 1977. The site itself consists of approximately 8,200 acres that is wholly owned by Florida Power. The site lies in a region of the state dominated by phosphate mining operations including mines, settling ponds, sand tailings piles, gypsum stacks, and chemical and beneficiation plants. The adjacent land uses consist almost entirely of active phosphate mining, or mined and reclaimed lands. See SSCA Figure 2.2.3-2. From the standpoint of land use compatibility, the availability of transportation facilities, the lack of noise and visual impacts during construction and operation activities, the Siting Board has already determined the site location to be suitable for power plant facilities. A discussion of land use in the area of the Hines Energy Complex site is presented in Section 2.2 of the Supplemental Site Certification Application.*

*Since the baseline date of August 7, 1977, there have been only a few major facilities built within a 10-mile radius including: Orange Cogeneration, Polk Power Station, Tiger Bay Cogeneration,* *and Mulberry Cogeneration. These facilities are located throughout the area surrounding the Hines Energy Complex. Based on their location with respect to each other, they will not result in impacts due to a concentrated industrial/commercial growth. Also, there is likely to be minimal interaction of air emissions from these plants with those from the Hines Energy Complex.*

*There are also very few residences near the plant site. The unincorporated community of Homeland is approximately 1 mile northeast of the site boundary.*

*The existing commercial and industrial infrastructure should be adequate to provide any support services that the Project might require. Construction of the Project will occur over a 24-month period. The construction workforce is expected to peak at 350 and average 145 employees. It is anticipated that many of these construction personnel will commute to the Site. The workforce needed to operate the proposed Project represents a small fraction of the population present in the immediate area. Population and housing impacts from construction and operation will be minimal because little development into the area is anticipated. Additionally, there are expected to be minimal air quality impacts due to associated industrial/commercial growth given the location at the existing Hines Energy Complex away from the existing industrial and commercial activities.*

*Since 1977, Polk County has been classified as attainment for all criteria pollutants. The nearest ambient monitors to the Project are located at Mulberry and Lakeland (AIRS Nos. 121052006-1 and 121056006-1). Data collected from these stations are considered to be representative of air quality in Polk County. A summary of the maximum pollutant concentrations measured in Polk County from 1998 through 2001 is presented in Table 2.3.7-7 of the SSCA application. These data indicate that the maximum air quality concentrations measured in the region comply with and are well below the applicable ambient air quality standards.*

*Additionally, results of air modeling analyses demonstrate that the Project will comply with all applicable AAQS and PSD increments.*

## ADDITIONAL COMMENTS

Comments from EPA and NPS will be forwarded when received.

***Response:***

*Comment noted. No additional response required.*

## ADMINISTRATIVE REQUIREMENTS AND CONTACT INFORMATION

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature.
If there are any questions, please contact Greg DeAngelo (review engineer) at (850)921-9506 and e-mail gregory.deangelo@dep.state.fl.us. Matters regarding modeling issues should be directed to Deborah Galbraith (meteorologist) at (850)921-9537 and e-mail deborah.galbraith@dep.state.fl.us.

*Response:*

*Comments noted. Please find enclosed (Enclosure 4) a statement, signed and sealed by a professional engineer, which covers the responses to the "Bureau of Air Regulation Questions" portion of this letter.*

**Southwest Florida Water Management District Questions**

***[Note: The following Background section is provided by Florida Power for clarification related to the following sufficiency items provided by the Southwest Florida Water Quality Management District ]***

*Background*

*Florida Power has a number of applications pending before the Southwest Florida Water Management District (SWFWMD) regarding water use at the Hines Energy Complex, specifically (a) the emergency use of groundwater from Florida Power's Tiger Bay co-generation facility for Power Blocks 1 and 2; (b) groundwater use for Power Block 3; and (c) development of the Aquifer Recharge and Recovery System (ARRP) for Power Blocks 4 – 6. These applications are consistent with the overall water use approved in the Hines Energy Complex ultimate site capacity certification. To clarify the nature of these applications and how they fit into the ultimate site capacity certification, Florida Power is providing the following background information.*

*In 1994, the Governor and Cabinet (with SWFWMD review and approval) certified the Hines Energy Complex for an ultimate site (power generation) capacity of 3,000 megawatts. This ultimate site certification provides that Florida Power will build the Hines Energy Complex in six "power blocks" or phases of generating capacity. The ultimate site capacity certification constitutes a determination that the Hines Energy Complex site has the environmental resources – including water - necessary to support an ultimate power generation capacity of 3,000 megawatts of combined cycle generating.*

*At 3,000 MW ultimate site capacity, the Hines Energy Complex will require 32 MGD of water from a combination of sources, including reclaimed water, internal reuse of wastewater, water cropping, offsite non-potable water sources and ground water. Water will be needed for makeup requirements of the cooling pond, personal and sanitary needs of employees and visitors, and various plant processes. With the exception of quantities needed to support potable and sanitary needs, the 1994 ultimate site capacity certification does not allow use of ground water to support Power Blocks 1 and 2, except as approved by SWFWMD under circumstances constituting an emergency. Florida Power is proposing no changes to the groundwater use approved for personal and sanitary needs in the 1994 certification.*

*The 1994 certification also approved the construction of Power Block 1 - an initial 470 megawatt combined cycle unit. In May 2001, the Governor and Cabinet (with SWFWMD review and approval) certified Power Block 2 - a 530 megawatt combined cycle electrical generating plant. Except in emergency circumstances, Power Blocks 1 and 2 will not use groundwater for cooling water makeup, but instead will use recycled wastewater, reclaimed water from the city of Bartow,* *and captured on-site rainwater from the Hines Energy Complex's water cropping system. Florida Power is proposing no changes to the water use for Power Blocks 1 and 2 as part of this Power Block 3 application. By a separate request, Florida Power is proposing to clarify that groundwater may be transferred from its Tiger Bay co-generation facility to Hines in emergency circumstances.*

*The 3,000 MW ultimate site capacity certification approved in 1994 provides that, after evaluating the feasibility of water conservation measures and non-potable water supplies, Florida Power may use up to 17.5 MGD of Floridan aquifer groundwater for Power Blocks 3 – 6. At this time, Florida Power believes that all feasible water conservation measures and non-potable water supplies have been employed. Therefore, pursuant to the ultimate site capacity certification, Florida Power is requesting groundwater use for Power Block 3.*

*This Power Block 3 application involves no changes to the water crop system that was reviewed and approved by SWFWMD in 1994 as part of Power Block 1 and again by SWFWMD in 2001 as part of Power Block 2. This Power Block 3 application also involves no changes to any other water use already approved for Power Blocks 1 and 2.*

*The 3,000 MW ultimate site capacity certification approved in 1994 also provides that, if SWFWMD adopts rules limiting groundwater use generally within the SWUCA, Florida Power may only use up to 5 MGD of groundwater for Power Blocks 3 – 6. In such case, Florida Power can use groundwater above 5 MGD only if Florida Power can offset that use by other means. Florida Power is proposing the ARRP system as a means of offsetting groundwater use to generate water for Power Blocks 4 – 6. The ARRP system involves no changes to the water use approved for Power Blocks 1 and 2, and no change to the water crop system.*

1. Please provide a revised version of Section 3.5 of the current Power Block 3 Supplemental Site Certification submittal. A note in The Table of Contents of Volume I of the submittal indicates that Section 3.5 "...needs further revision." Please note that staff needs an integrated submittal as much as possible, rather than a piece meal submittal that confuses our time frames and renders staffs review less efficient. Also, please note that your submittal of a revised version of Section 3.5 may generate additional questions. Please take into consideration in your revised submittal the following observations. [400-2.091, Florida Administrative Law (F.A.C.), 40D-2.101, F.A.C., 400-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The referenced phrase is a scrivener's error that was inadvertently included. This comment appears only in the Table of Contents and not in Section 3.5. The information contained in Section 3.5 of the application as submitted, is complete.*

2. Please submit a competed Water Use Permit (WUP) Application and a completed Supplemental WUP Form for Industrial Water Use must be properly completed, signed and returned to the District. No portion of the application may be omitted. For example, all the information about the wells (ID No., casing diameter, depth, status, etc., need to be provided/confirmed, and so forth with the other items of information. [400-2.091, F.A.C., 400-2.101, F.A.C., 400-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

*Response:*

*Please find enclosed (Enclosure 5) a completed Water Use Permit Application form. Please note that this information is being provided to address the sufficiency requirements of the Supplemental Site Certification Application for this project and not to obtain a separate Water Use Permit, as this is not required for this project. The enclosed form provides information for Hines Energy Complex Power Block 3 project only. Information in the file related to WUP 2010944 provides information from the previous Site Certification activities.*

3. In completing the application, as requested in item 2 above, all of the information specified in the application must be provided. For example, information about all surface water withdrawals (e.g. the cooling pond) and groundwater withdrawals should be provided. Also, information about staff gauges and monitoring wells should be provided. [400-2.091, F.A.C., 400-2.101, F.A.C., 400-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

*Response:*

*Refer to the response to Item 2 above. In addition, the water balance diagrams mentioned in Item 5 below show the anticipated water uses and sources at Hines Energy Complex for both an average rainfall year and a drought rainfall year.*

4. Provide a location map, not necessarily a blue-line aerial map, showing a north arrow, a scale no less than 1" = 800 feet, major land marks such as main roads or highways, referenced to Section, Township and Range, and indicating the following items of information that are associated with your current application:

   a. The boundaries of contiguous property owned — this includes all contiguous property owned regardless of whether or not it constitutes part of the project that constitutes the subject matter of your current application; and

   b. The specific location of all existing (active or inactive) and proposed withdrawal points on the property associated with your current. Label each withdrawal point with an Owner ID No. and indicate the distance in feet between the withdrawal point and the closest east/west and north/south property.
   [400-2.091, F.A.C., 400-2.101, F.A.C., 400-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

*Response:*

*An updated map of the Hines Energy Complex is enclosed (Enclosure 6) which shows the proposed well locations. The maps included in WUP 20010944 show well locations and DID 1 through 6 are already listed with latitude and longitude.*

5. The permitted groundwater Annual Average Daily (MD) and Peak Month (PMD) are 17.5 million gallons per day (MGD) on a non SWUCA basis. Only 5 MGD are permitted under SWUCA rules. Accordingly, please explain and justify the information provided in the Water Balance Diagrams of the current submittal, wherein groundwater use quantities for PB 3 are indicated as 2.428 MGD in an average year and 5.143 MGD in drought year.

Please explain how are these water balances related to groundwater quantities permitted for PB 3 through 6. FPC should now have data collected since PB#1 came on-line to confirm or adjust the assumptions made in developing the analysis used for quantifying the amounts of water for the project. As FPC develops the remaining three power blocks in the future, they should have even more historical data available to be used in assessing water requirements. Thus it is expected that FPC would collect this data and use it to show justification for the consumptive use quantities requested.

It is not clear how the construction of PB3 will cause some of the changes in the water balances provided. For example, it is not clear how the construction of PB 3 will increase pond seepage from 500,000 gpd to 1,000,000 gpd or why evaporation from the cooling pond will increase from 7,170,000 gpd to 9,300,000 gpd as indicated in these figures. Please explain all variations in the water balance for PBs 1, 2, and 3.

PB 1 has been on-line since 1999. FPC should be able to furnish three years of data indicative of water use at the site. Specifically:

a. Have there been any overflows from the existing cooling pond? If so, when? At what water level elevation and what average rate, maximum rate, duration, monthly quantities, annual quantities?
b. What is the monthly average water elevation in feet and the total dissolved salts (TDS) in milligram per liter (mg/I) in the cooling pond by month. Indicate minimum acceptable elevation and overflow elevation;
c. Provide Monthly average power production (MWH) from PB#1. Indicate any months when the steam turbine generator was not used;
d. Provide monthly average values for cooling water supply temperatures, cooling water return temperatures, ambient air dry bulb temperatures, and ambient wet bulb temperatures at complex;
e. Provide monthly precipitation amounts as measured with on-site rain gauges.
f. Provide monthly quantities (1,000 gallons) and TDS (mg/I) of water withdrawn from on-site wells for potable water system;
g. Provide monthly quantities (1,000 gallons) and TDS (mg/I) of reclaimed water received on-site;
h. Provide monthly quantities of water processed in each on-site treatment system; Provide water budget diagrams showing average and maximum month water budgets that reflect actual experience to date with operation of PB#1. Provide a discussion relating values in water budget diagram to historical data. Use mass and energy balances to reconcile estimates for runoff, evaporation and seepage; and
j. Provide a discussion relating values in figures 3.5.1-2, 3 & 4 to water budget diagram based on historical data.

[400-2.091, F.A.C., 400-2.101, F.A.C., 400-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The water balance diagrams were prepared for average (Fig. 3.5.1-3) and one-year-in-ten drought (Fig. 3.5.1-4) rainfall conditions. These diagrams are for the combined water use of Power Blocks 1, 2 and 3. Figure 3.5.1-2 shows the water balance diagram and amounts from the previous site certification for combined Power Blocks 1 and 2. The differences between Figure 3.5.1-2 and Figure 3.5.1-3 show the increase water demand caused by Power Block 3. The* *groundwater sources of annual average 2.428 mgd and 5.143 mgd for a drought year are those additional needs for Power Block 3. Power Blocks 4, 5 and 6 are not included in these water balances.*

*The increase in water seepage from 0.5 to 1.0 mgd for the cooling pond is not attributable to the addition of Power Block 3, but rather to an updated evaluation of embankment seepage, which was recently completed by Ardaman and Associates (Enclosure 7).*

*The increase in cooling pond evaporation from 7.17 mgd to 9.3 mgd is directly attributable to the increased heat load from Power Block 3. This increase was predicted by Black and Veatch's evaporation models for the original Site Certification approved in 1994.*

*In regards to Items a. through j. above, the cooling pond is a non-discharge facility with no overflow. The pond is operated between 159 and 163 feet NGVD. See Enclosure 8 for Hines monthly rainfall and pond level.*

6. Indicate what specific groundwater withdrawal(s) will be used when Power Block (PB) 3 becomes online. State the Annual Average Daily (MD) and Peak Month Daily (PMD) quantities of groundwater that will be needed from such withdrawal(s) for PB 3. Provide documentation on how these quantities have been computed. Also compare these quantities with water quantities used for PBs 1 and 2, indicate the sources of these quantities and provide documentation on how each component of the these sources has been measured and/or computed. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*See Question 5.*

7. For each of the water uses that are associated with the project, indicate the AAD and PMD water quantities proposed to be used from all sources for Blocks 1, 2, and 3. Also, indicate the AAD and PMD quantities and the source (the specific withdrawal ID No.) of groundwater that will be used for each of those uses. The uses include but are not limited to, cooling water system, heat recovery boiler make-up water, reduction of oxides of nitrogen NOx emissions, flue-gas desulphurization, etc. Also please relate the actual water use in gallons of water used per MW of electricity produced (GPMW) for each of the water uses that are associated with the project site. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The specific average and peak demands for each water use component at the Hines Energy Complex are shown on Figures 3.5.1-2, 3.5.1-3, and 3.5.1.4. The Floridan Aquifer groundwater will come from production wells 1 and 2 (WUP 20010944 DID 1 and 2).*

8. Please provide an account of all water conservation measures taken and/or planned to be taken to reduce water consumption at the project site, through the use of the best available technology. Describe how each process or design aspect of water use at the plant has been selected and compare such process/design to other alternatives, from a water conservation perspective. For example, compare the existing cooling pond system to dry cooling, wet cooling tower, and hybrid (wet/dry) cooling tower. Also compare the effect of using different fuel types on the rate of water consumption. Please note that the comparison required here

should consider factors such as the entire life of the project, the changing value of water in an era of growing water scarcity, the feasibility of using brackish water from the lower Floridan aquifer for cooling, etc. In other words, provide documentation indicating at what price of water would a breakeven point be established between using dry cooling and other cooling processes. Similarly, discuss and compare the method used in reducing the NOx concentrations, vis-a-vis other more water conserving processes, e.g., water injection is less water consumptive than steam injection, and dry low (NOx) systems are less water consumptive than both of these two methods. Additionally, please discuss the feasibility and possible implementation, with time frames, the following:

a. If the anticipated cooling water return temperature is more than 10 degrees F above the average ambient dry bulb temperature, it might be possible to reduce consumptive water use with a sidestream dry cooling tower; and
b. Treatment of RO reject water to recover a portion of this water for reuse.

[40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.] [40D-2.091, F.A.C., 40D-2. 101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*Multiple water conservation measures are being employed at Hines currently and as part of Power Block 3. The generation technology being used at Hines, natural gas combined cycle, reduces water consumption by up to two thirds compared to traditional steam generation technology. As stated in previous applications, internal wastewater reuse to provide cooling pond make-up is being done as part of Power Blocks 1 & 2 and will also be part of Power Block 3. The primary reuse water is boiler blowdown. In addition, Power Blocks 1, 2, & 3 are designed with dry low-NOx fuel combustors that eliminate the need for water injection to control nitrogen oxides in the exhaust gas when burning natural gas. Water injection must be used when these units burn fuel oil, however, Florida Power will secure sufficient natural gas supplies that will allow this fuel type to be the primary fuel burned thereby minimizing the need for water injection. Florida Power will also accept limitations on the amount of fuel oil that can be burned by this unit in the facility's FDEP air permit that will further minimize the need for water injection.*

*Florida Power believes the cooling pond represents the best water conserving cooling technology that is viable in Florida. Cooling towers require greater amounts of make-up water than cooling ponds because cooling towers do not take advantage of direct precipitation and have greater water losses to evaporation. Florida Power does not believe dry cooling is a feasible technology at the Hines Energy Complex. Preliminary estimates for a dry cooling system to serve a 500 MW natural gas fired combined cycle power plant similar to Power Block 3 approaches $28,000,000. Although this is not a detailed cost estimate for Power Block 3 ( it is taken from a presentation by Black & Veatch, an engineering consulting firm, made to SWFWMD's Power Plant Task Force), Florida Power believes it is a representative cost estimate. Additional cost would be incurred for replacement power needed to offset the increased internal power requirements for dry cooling. These power requirements are double that of the cooling pond. The existing cooling pond has the capacity to support Power Block 3. The cooling pond was authorized in the original certification and has been approved by the Public Service Commission for Florida Power to recover its investment in the cooling pond from the Company's customers. Florida Power does not believe it is prudent to abandon the existing cooling pond being paid for by our customers and reinvest $28,000,000 (that would also be paid by our customers) to install dry cooling. Since Florida Power has made the investment in the cooling pond, the break even cost necessary to justify dry cooling is zero (there is no cost for the construction of a cooling pond that is associated with the cost of PB3). Therefore, dry cooling is not a cost effective option.*

*Further consider that during the summer, the peak time of year for power, the net power output of the unit would be reduced by approximately 18 MW if dry cooling were used compared to the cooling pond. This loss in power would need to be produced at another power plant. This would result in use of additional fuel, additional air pollutants, significantly more noise pollution and potentially additional water use for this replacement generation produced at a higher cost to generate. Stated differently, maintaining the approximate 500 MWs of generation using dry cooling results in greater air and noise emissions compared to the same unit using a cooling pond. Florida Power does not believe the cumulative net environmental benefit of dry cooling exceeds that of a cooling pond. The environmental impact resulting from the increased air and noise pollution out weigh any impact from the use of groundwater to provide make-up to the cooling pond. This statement is supported by the existing site certification consumptive use language written by SWFWMD stating that up to 5 MGD of groundwater withdrawal has been determined to meet district rule criteria.*

*The significantly higher cost and environmental disadvantages of dry cooling make this a non-viable alternative to the existing cooling pond.*

9. Revisit the availability of wastewater for reuse from each of the following sites:

    a. The City of Fort Meade;
    b. The City of Lakeland wastewater out-fall into the North Prong of the Alafia River; and
    c. The City of Mulberry.

    Provide documentation of your efforts to date to obtain reuse water from these sources, and the potential of their future availability. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The availability of wastewater from the cities in the vicinity of Hines Energy Complex is limited. Representatives from Florida Power recently met with Ft. Meade's City Manager to discuss the availability and feasibility of receiving Ft. Meade's treated effluent. It was determined from this meeting that this source is not viable because the city is currently under contract with Cargill to provide 100% of the effluent and a new pipeline would need to be constructed through the middle of Ft. Meade to provide conveyance to Hines. Ft. Meade's wastewater treatment plant produces 0.5 MGD AAD and 0.8 MGD PMD flows. The pipeline cost when compared to these flows is not cost effective even if the water were available, which it is not.*

*Florida Power is currently in the process of setting up meetings with the City of Lakeland and the City of Mulberry. In the case of the City of Lakeland, Florida Power will evaluate the feasibility of reusing the city's effluent. However, as the District is aware, the major component of this effluent would be the industrial wastewater produced by the blowdown from Lakeland Electric's cooling towers. Florida Power will explore the possibility of treating and reusing this industrial wastewater. However, at this time, Florida Power cannot guarantee the feasibility of this source. The feasibility of using the City of Mulberry's treated effluent cannot be discussed at this time due to the uncertainties of quantity, quality and the expense to pipe the water to Hines.*

10. Please provide reasonable timeframes for reporting (e.g., every six months) and a framework for periodic reporting to the FOEP and to the District on your water conservation activities and efforts, including efforts made to obtain reuse water from all potential sources. Such efforts also include attempts to discourage ALCOA from dredging the onsite ponds as a means of wastewater disposal via the proposed pipeline to the cooling pond at Hines energy Complex. The reporting framework shall also incorporate every aspect, structure, design or process at

the power plant that has bearing on water conservation. For example, the reporting framework shall include, but it will not be limited to a discussion of all potential sources mentioned above, but it will also address the feasibility of exploiting the Lower Floridan aquifer brackish water, quantities offsetting Upper Floridan aquifer quantities permitted to the permittees, etc.). The reporting framework shall also include, but will not be limited to, discussing water uses at the power plant as listed in Item 7 above, the best available technology and processes for water conservation at the power plant and how the permitee is pursuing up-to-date information on this matter as well as how the permittee plans to incorporate such knowledge in the operation of the existing Power Blocks as well as in the prospective incremental Power Blocks to be built in the future. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*This type of information is required to be provided each time that a Supplemental Site Certification Application is submitted for each incremental Power Block. This currently is approximately every two years. This is a sufficient timeframe to provide this type of information. In the event that subsequent Supplemental SCAs are not submitted on this schedule, Florida Power will consider a Condition of Certification that provides for reporting every two years.*

11. Please note that the following question was asked in the District's Clarification of Additional Information Letter dated October 14, 2002, regarding the Aquifer Recharge and Recovery Project. It is presented here so that a Condition of Certification (CoC) can be formulated to be added along with other changes of or additions to the CoCs of the Hines' Site Certification. The question relate to water cropping as follows:

    It is imperative that FPC conduct the necessary monitoring and analysis to evaluate the impacts, e.g., decrease of runoff from the project site to the Peace River or its tributaries, due to water cropping, and determine whether or not such cropping would be detrimental to the river's natural system or legal existing users. The fact that the SC does not contain Conditions of Certification (CoC) that require such monitoring/evaluation does not preclude FPC from further evaluation of the impacts of FPC's practices of water cropping on aquifer recharge and Peace River flow. Accordingly, provide a Monitoring and Mitigation Plan, subject to District approval, for the monitoring, evaluation, and mitigation of any adverse impacts in this regard. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The water crop system was developed as a means of reducing Florida Power's dependence on groundwater. The water crop system was approved by SWFWMD as part of the original site certification in 1993-94 and then again as part of Power Block 2 in 2001. According to SWFWMD's August 25, 1993, agency report, SWFWMD reviewed the original site certification for compliance with the permitting criteria in chapters 40D-2, 40D-3, and 40D-4, F.A.C.*

*According to SWFWMD's August 25, 1993, agency report, the Hines Energy Complex was constructed on a disturbed former mining site. Approximately half of the site was required to be reclaimed in accordance with DEP's mining reclamation rules. The remaining half of the site was mined prior to mandatory mining reclamation requirements. This half of the site is referred to as "non-mandatory areas."*

*The non-mandatory areas did not contribute to off-site systems as of October 1984 when SWFWMD adopted Chapter 40D-4. Therefore, SWFWMD considers these non-mandatory areas to be existing closed basins from a surface water hydrology analysis standpoint. These areas are evaluated as closed basins because no rule or law requires that these non-mandatory areas to be reclaimed in a manner providing surface water discharge reflecting the pre-mining or pre-1975 condition.*

*SWFWMD's August 25, 1993, agency report notes that Florida Power would reclaim the mandatory and most of the non-mandatory reclamation areas in a fashion that would allow for water cropping or zero discharge. To offset the reduction in flows to Camp Branch and McCullough Creek, Florida Power will use areas N-11C, N-13, N-9B, N-11A, a portion of the old Estech plant, SA-10 and a portion of SA-12 to contribute flows to these two systems. SWFWMD's August 25, 1993, agency report states that these flows will adequately compensate for the zero discharge nature of the water cropping system and address the potential for adverse environmental impacts off-site. Florida Power developed hydrographs depicting the net effect of these activities on the flows in Camp Branch and McCullough Creek as part of this original review and determination by SWFWMD. These hydrographs are resubmitted in Enclosure 9.*

*Note also that the Final Order of the Governor and Cabinet approving the ultimate site certification in 1994 adopted the recommended order of the Administrative Law Judge. Paragraph 64 of the Administrative Law Judge's recommended order provides as follows:*

> *64. The Polk County Site [now Hines Energy Center] has been designed to function as a "zero discharge" facility. No surface water will be withdrawn from or discharge to any offsite surface water body as a result of plant operations. Certain non-industrial areas within the Polk County Site will be designed, however, to produce offsite drainage to enhance flows to McCullough Creek and Camp Branch. Flow to McCullough Creek will be enhanced by drainage from parcel SA-10, an offsite portion of the Estech Silver City Plant Site, and the southernly portion of parcel SA-12. Drainage from parcels N-11A, N-13, N-9B, Tiger Bay East and Tiger Bay will enhance flows to Camp Branch. Additionally, FPC has agreed to explore the possibility of restoring drainage to Six Mile Creek if on site water cropping produces more water than FPC needs for power plant operations and if such drainage can be accomplished without additional permits. <u>The net effect of the drainage enhancement plans will be to equal or improve flows to McCullough Creek and Camp Branch over the baseline condition for the site</u>.(emphasis added)*

*Thus, SWFWMD, DEP, and the Administrative Law Judge reviewed the effects of the water cropping system on offsite areas and concluded that the system, combined with other restoration efforts, would compensate for or be a net improvement over the baseline condition. Florida Power is currently working to implement the watercrop system as previously approved and does not intend to extend the watercrop operation outside of those approved lands. In this Power Block 3 application, Florida Power is not proposing any changes to the water cropping system SWFWMD previously approved.*

12. Please provide documentation to demonstrate that rainwater and stormwater capture constitutes a reasonable beneficial use of water. [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The Hines Energy Center Condition of Certification XXVI.A.14.c. (PA 92-33) (reviewed and approved by SWFWMD) specifically states that on-site rainwater and stormwater capture and use constitute a reasonable and beneficial use of water. Florida Power is not proposing any changes to the rainwater and stormwater capture system (water crop) SWFWMD previously approved. Please refer to the Question 11 Response for additional detail.*

13. As the CoCs are modified or as additional CoC(s) are added, per the current submittal, as well as per the amendment for the water transfer from the Tiger Bay to the Hines, and per the modification for the ARRP, the following items need to be identified/verified, including providing latitude and longitude, when applicable, and located on the location map mentioned in question 4:

    a. The specific Owner ID No., location, and diameter of the delivery point of reuse water from the Bartow Wastewater Treatment Plant;
    b. The specific Owner ID, location, and diameter of the delivery point of water shortage supply from the Tiger Bay to the Hines' cooling pond;
    c. The specific Owner ID No. and location of the staff gauge in cooling pond;
    d. The specific locations, Owner ID Nos., depths (cased and total), diameters, of all injection well(s) and monitoring wells associated with the ARRP as well as associated with monitoring and mitigation plan for water cropping.

    [40D-2.091, F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The following ID Numbers and locations are:*

| | | | |
|---|---|---|---|
| *DID 7* | *Bartow Effluent Discharge* | *Lat/Lon* | *27 47 30 / 81 50 54* |
| *DID 8* | *ALCOA/Tiger Bay Discharge* | *Lat/Lon* | *27 47 30 / 81 51 45* |
| *DID 9* | *Cooling Pond Staff Gauge* | *Lat/Lon* | *27 47 30 / 81 51 47* |

*See Enclosure 10 for Well locations and details.*

14. Please provide all the information necessary to comply with the provisions of PA-33SA Conditions of Certification XXVIA.14.b.ii. and iii. for this supplemental application for the construction and operation of a further increment of generating capacity at Hines. [40D-2.091,F.A.C., 40D-2.101, F.A.C., 40D-2.301, F.A.C., 2.1.1, Basis of Review for Water Use Permit Applications.]

***Response:***

*The information related to these provisions can be found in the Supplemental Site Certification Application at Section 3.5.*

**Florida Department of Transportation Questions**

The Florida Department of Transportation has reviewed the transportation related information relative to the subject application for sufficiency. The application bases its transportation impacts on a 1992 traffic study. The Department recommends that new traffic counts be taken and the traffic study be updated based on these more recent counts. Mr. John Czerepak of the Department's District 1 Office in Bartow will be pleased to assist the applicant in the development of acceptable data. Mr. Czerepak can be reached by phone at (941) 519-2343.

In addition, the Department will need to know the height of all new structures associated with the new unit to evaluate any potential aviation impacts.

***Response:***

*As part of the initial site certification proceeding for the Hines Energy Complex in 1992 to 1994, Florida Power, its transportation consultants and reviewers at the Florida Department of Transportation evaluated the traffic impacts of the full build-out of the Hines Energy Complex, up to the planned 3000 MW of generating capacity and potential coal gasification facilities. The traffic impact analyses performed at that time evaluated the impact of traffic expected with each of the six planned units at the site, including the currently-proposed Unit 3. At peak employment at the site, it was found that local roadways would meet local and state level of service standards, with the roadway improvements that were required to be made as part of the initial certification proceeding. Florida Power has undertaken the required roadway improvements needed for full project buildout. Thus, the issue of traffic impact for each unit at the Hines Energy Complex has already been evaluated and mitigation or improvements already required and undertaken. The current conditions of certification originally proposed by the Department of Transportation will also be met with each subsequent unit, including the proposed Unit 3.*

*Since the impacts have already been addressed for this unit, and given that the addition of Unit 3 will only result in 4-6 additional employees, it is unnecessary to conduct a new traffic impact analysis for Unit 3, using updated traffic counts. The information contained in the Unit 3 site certification application was presented to document that the Unit 3 traffic for construction and operation was within the levels already evaluated and conditioned as part of the initial certification proceeding. It does not represent new traffic, nor require a new traffic impact analysis.*

*The heights of the two new stacks associated with the project are 125 feet each. This is the same height as the existing stacks at the facility.*

*[End of Responses ]*

We look forward to working with you, the Department and other agencies participating in the certification process. Should you, your staff, or any other agency representatives have any questions regarding this response to sufficiency questions, please do not hesitate to contact me at (813) 826-4363.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

Enclosures

jjh/JJH049

c: (see attached list)

## List of Parties Receiving Copies of the Hines 3 SSCA Response to Sufficiency Requests – December 2002

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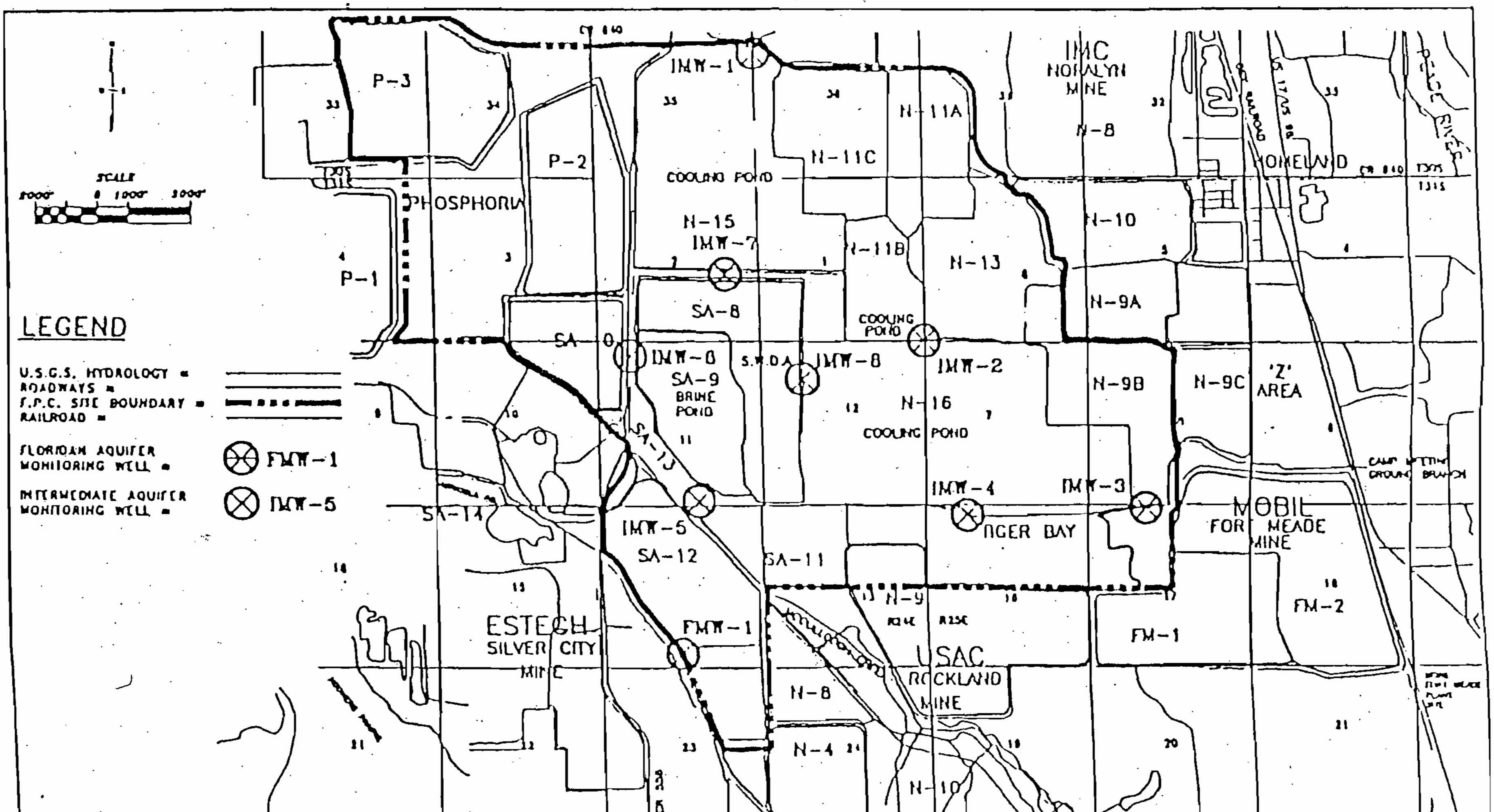
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400




Florida Power CORPORATION

Polk County Site

FIGURE 1
MONITORING WELL LOCATIONS

MWLOC DWC
REV. 10/93

Florida Power
CORPORATION

March 16, 1998

Mr. Michael Hickey
Florida Department of Environmental Protection
Southwest District
3804 Coconut Palm Drive
Tampa, Florida 33619-8318

Dear Mr. Hickey:

Re: Florida Power Corporation - Hines Energy Complex
Site Certification PA 92-33 - Groundwater Monitoring Plan

In accordance with the provisions of Condition XVIII.A.6. of the above certification, attached are the well completion report and logs for the facility.

If you have any questions concerning this submittal, please do not hesitate to contact me at (813) 866-4290.

Sincerely,

B.R. Melton

B. Randall Melton
Environmental Specialist

Attachment
cc: Mr. Hamilton Oven - FDEP Tallahassee
Ms. Dawn Turner - SWFWMD Tampa
Mr. Robert Viertel - SWFWMD Bartow
Permits Data - SWFWMD Brooksville

ENGELHARD

Golder Assoc.
501F - Combined Cycle
CO and SCR Catalyst Systems
Engelhard Budgetary Proposal EPB00664-Rev. 1
March 15, 2000

**Performance Data**

| | | | | | |
|---|---|---|---|---|---|
| FUEL | NG | NG | NG | NG | Oil |
| TURBINE EXHAUST FLOW, lb/hr | 3,600,000 | 3,600,000 | 3,600,000 | 3,600,000 | 3,750,000 |
| TURBINE EXHAUST GAS ANALYSIS, % VOL. N2 | 74.37 | 74.37 | 74.37 | 74.37 | 71.87 |
| O2 | 12.51 | 12.51 | 12.51 | 12.51 | 11.10 |
| CO2 | 3.74 | 3.74 | 3.74 | 3.74 | 5.20 |
| H2O | 8.45 | 8.45 | 8.45 | 8.45 | 10.90 |
| Ar | 0.93 | 0.93 | 0.93 | 0.93 | 0.93 |
| GIVEN: TURBINE CO, ppmvd @ 15% O2 | 25 | 25 | 25 | 25 | 30 |
| CALC.: TURBINE CO, lb/hr | 99.7 | 99.7 | 99.7 | 99.7 | 141.8 |
| GIVEN: TURBINE NOx, ppmvd @ 15% O2 | 25 | 25 | 25 | 25 | 42 |
| CALC.: TURBINE NOx, lb/hr | 163.8 | 163.8 | 163.8 | 163.8 | 326.2 |
| CALC. GAS MOL. WT. | 28.38 | 28.38 | 28.38 | 28.38 | 28.28 |
| FLUE GAS TEMP. @ CO and SCR CATALYST, F | 650 | 650 | 650 | 650 | 650 |
| DESIGN REQUIREMENTS | | | | | |
| CO CATALYST CO OUT, ppmvd @ 15% O2 | 2.5 | 2.5 | 2.5 | 2.5 | 3.0 |
| SCR CATALYST NOx OUT, ppmvd @ 15% O2 | 3.0 | 3.0 | 2.5 | 2.5 | 25 |
| NH3 SLIP, ppmvd @ 15% O2 | 9 | 5 | 9 | 5 | 12 |
| GUARANTEED PERFORMANCE DATA | | | | | |
| CO CATALYST CO CONVERSION, % - Min. | 90.0% | 90.0% | 90.0% | 90.0% | 90.0% |
| CO OUT, lb/hr - Max. | 10.0 | 10.0 | 10.0 | 10.0 | 14.2 |
| CO OUT, ppmvd @ 15% O2 - Max. | 2.5 | 2.5 | 2.5 | 2.5 | 3.0 |
| CO PRESSURE DROP, "WG - Max. | 1.3 | 1.3 | 1.3 | 1.3 | 1.3 |
| SCR CATALYST NOx CONVERSION, % - Min. | 88.0% | 88.0% | 90.0% | 90.0% | 40.4% |
| NOx OUT, ppmvd @ 15% O2 - Max. | 3 | 3 | 2.5 | 2.5 | 25 |
| NOx OUT, lb/hr - Max. | 19.7 | 19.7 | 16.4 | 16.4 | 194.3 |
| EXPECTED AQUEOUS NH3 (28% SOL.) FLOW, lb/hr | 268.0 | 233.4 | 272.4 | 237.8 | 297.2 |
| NH3 SLIP, ppmvd @ 15% O2 - Max. | 9 | 5 | 9 | 5 | 12 |
| SCR PRESSURE DROP, "WG - Max. | 2.4 | 2.6 | 2.6 | 2.8 | |
| **CO SYSTEM** | **$773,000** | **$773,000** | **$773,000** | **$773,000** | |
| **REPLACEMENT CO MODULES** | **$674,000** | **$674,000** | **$674,000** | **$674,000** | |
| **SCR SYSTEM** | **$1,526,000** | **$1,630,000** | **$1,630,000** | **$1,738,000** | |
| **REPLACEMENT SCR MODULES** | **$1,042,000** | **$1,144,000** | **$1,144,000** | **$1,250,000** | |

Table A-25 Summary of Maximum Potential Annual Emissions for the CT/HRSG

| Pollutant | | Annual Emissions (tons/year) [a] | | | Maximum Emissions (tons/year) [b] | | | | PSD Significant Emission Rates |
|---|---|---|---|---|---|---|---|---|---|
| | | Natural Gas | Natural Gas | Distillate Oil | Case A | Case B | Case C | Case D | |
| | Load: | 100% | 60% | 100% | | | | | |
| | Hours: | 8,760 | 3,000 | 1,000 | | | | | |
| One Combustion Turbine- Combined Cycle | | | | | | | | | |
| SO2 | | 22.4 | 5.4 | 48.6 | 22.4 | 20.1 | 68.4 | 66.1 | 40 |
| PM/PM10 | | 34.4 | 8.8 | 29.8 | 34.4 | 31.4 | 60.3 | 57.3 | 25/15 |
| NOx | | 101 | 24 | 44 | 101.2 | 90.4 | 133.4 | 122.6 | 40 |
| CO | | 184 | 219 | 53 | 184.0 | 340.0 | 216.0 | 372.0 | 100 |
| VOC (as methane) | | 19.1 | 7.5 | 10.5 | 19.1 | 20.0 | 27.4 | 28.4 | 40 |
| Sulfuric Acid Mist | | 3.4 | 0.8 | 7.4 | 3.4 | 3.1 | 10.5 | 10.1 | 7 |
| Lead | | 0 | 0.00E+00 | 1.04E-02 | 0.0E+00 | 0.0E+00 | 1.0E-02 | 1.0E-02 | 0.6 |
| Mercury | | 6.41E-06 | 1.54E-06 | 6.05E-04 | 6.4E-06 | 5.8E-06 | 6.1E-04 | 6.1E-04 | 0.1 |
| Total HAPs | | 1.93 | 0.77 | 1.80 | 1.9 | 2.0 | 3.5 | 3.6 | 25 |
| Two Combustion Turbines- Combined Cycle | | | | | | | | | |
| SO2 | | 44.9 | 10.7 | 97.1 | 44.9 | 40.2 | 136.9 | 132.3 | 40 |
| PM/PM10 | | 69 | 18 | 60 | 69 | 63 | 121 | 115 | 25/15 |
| NOx | | 202 | 48 | 88 | 202 | 181 | 267 | 245 | 40 |
| CO | | 368 | 438 | 106 | 368 | 680 | 432 | 744 | 100 |
| VOC (as methane) | | 38.1 | 15.0 | 21.0 | 38.1 | 40.1 | 54.8 | 56.7 | 40 |
| Sulfuric Acid Mist | | 6.9 | 1.65 | 14.87 | 6.87 | 6.16 | 20.96 | 20.25 | 7 |
| Lead | | 0.00E+00 | 0.00E+00 | 2.09E-02 | 0.00E+00 | 0.00E+00 | 2.09E-02 | 2.09E-02 | 0.6 |
| Mercury | | 1.28E-05 | 3.07E-06 | 1.21E-03 | 1.28E-05 | 1.15E-05 | 1.22E-03 | 1.22E-03 | 0.1 |
| Total HAPs | | 3.9 | 1.55 | 3.60 | 3.87 | 4.09 | 7.02 | 7.25 | 25 |

a Based on 59 oF compressor inlet air temperature

b Maximim emission cases:

| Operation | Number of Hours for Operation | | | |
|---|---|---|---|---|
| | Case A | Case B | Case C | Case D |
| 100 % Load | 8,760 | 5,760 | 7,760 | 4,760 |
| 100 % Load -Oil | 0 | 0 | 1,000 | 1,000 |
| 60% Load-Gas | 0 | 3000 | 0 | 3,000 |
| Total hours | 8,760 | 8,760 | 8,760 | 8,760 |

**Golder Associates Inc.**

6241 NW 23rd Street, Suite 500
Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

December 16, 2002

0237539

Trina Vielhauer, Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 23399

RE: FLORIDA POWER – HINES ENERGY COMPLEX POWER BLOCK 3
DEP FILE 1050234-006-AC (PSD-FL-330)
ADDITIONAL INFORMATION REQUEST
PROFESSIONAL ENGINEER CERTIFICATION

Attention: A. A. Linero, P.E., Administrator, New Source Review Section

Dear Al:

This correspondence provides the Professional Engineer Certification for the responses to the sufficiency questions addressing the additional information requested by the Bureau of Air Regulation for the Florida Power Hines Energy Center Power Block 3. The responses for the air construction/PSD permit were prepared by me or under my direction and cover the additional information requested by Greg DeAngelo and Deborah Gailbraith in the October 4, 2002 memorandum to Hamilton Oven.

Please call if there are any questions.

Sincerely,

GOLDER ASSOCIATES INC.

Kennard F. Kosky

Kennard F. Kosky, P.E.
Principal
Registered Professional Engineer No. 14996
(Golder Associates, Inc. Certificate of Authorization No. 00001670)

Seal

KFK/jkw

cc: Jamie Hunter, Lead Environmental Specialist
Greg DeAngelo, Bureau of Air Regulation
Deborah Gailbraith, Bureau of Air Regulation

P:\Projects\2002\0237539 FPC Hines Energy Complex\4\4.1\L121602.doc

# INDIVIDUAL WATER USE PERMIT APPLICATION

*SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT*

2379 BROAD STREET • BROOKSVILLE, FL 34609-6899 • (352) 796-7211 or FLORIDA WATS 1 (800) 423-1476
(SEE LAST PAGE OF THIS FORM FOR YOUR LOCAL PERMITTING OFFICE)

## USE FOR QUANTITIES OF 500,000 GALLONS PERDAY OR GREATER

THIS FORM MUST BE COMPLETED FOR ALL APPLICANTS REQUESTING ANNUAL AVERAGE QUANTITIES OF 500,000 GPD OR GREATER. OTHER APPLICANTS MUST COMPLETE THE APPLICATION FORM CORRESPONDING TO THE PROPOSED QUANTITY. THIS INFORMATION IS REQUESTED IN ACCORDANCE WITH RULES 40D-2.101 AND 40D-2.301, FLORIDA ADMINISTRATIVE CODE.

*AN ASTERISK INDENTIFIES ITEMS TO BE INDICATED ON SITE MAP; YOU MAY USE THE MAP REQUESTED IN ITEM IV, SECTION B OF THE WUP APPLICATION.

**PLEASE SUBMIT THREE COPIES OF THIS APPLICATION ALONG WITH THREE COPIES OF THE APPROPRIATE SUPPLEMENTAL FORM (IF REQUIRED), DRAWINGS, CALCULATIONS, ETC.**

## I. GENERAL INFORMATION

1. Type of Application (Check One): ☐ New ☐ Renewal ☒ Modification
2. Water Use Permit Number (If application is for renewal or modification): 20012367 and 20010944

NOTE: "Applicant" is the name under which the permit will be issued (examples: Robert Jones; Baker Groves, Inc., Acme Industries, City of Sundale.) All correspondence will be addressed to the applicant unless an alternate contact is requested in Item 4.

**3. APPLICANT**

NAME Progress Energy Hines Energy Complex TELEPHONE (863) 519-6100

ADDRESS 7700 CR 555 COUNTY Polk

CITY, STATE, ZIP Bartow, Fl 33830

Applicant is: ☒ Owner ☐ Lessee ☐ Other ____

**4. CONTACT OR CONSULTANT - Address all correspondence to the person identified below?** ☐ Yes ☐ No

NAME John Hunter COMPANY: Progress Energy

ADDRESS P.O. Box 14042, BB1A TELEPHONE (727 )826-4363

CITY, STATE, ZIP ST. PETERSBURG, FLORIDA 33733

**5. OWNER (IF OTHER THAN APPLICANT)**

NAME

ADDRESS TELEPHONE ( )

CITY, STATE, ZIP

## II. PROPERTY CONTROL

1. Provide a legal description of the property served by this application. ☐ Attached See WUP 2010944
2. This property is: ☒ Owned by the applicant ☐ Leased by the applicant ☐ Applicant has other legal control
3. Leased property: Provide a copy of either (check type of document that is attached):
   ☐ Copy of lease ☐ Letter signed by the property owner describing the lease arrangement and the duration of the lease

**NOTE:** Permits will not be issued for a duration longer than the lease, unless the lease is renewable. If renewable, the applicant may be required by Permit Condition to provide a copy of the renewed lease at the appropriate time. The property owner and the lessee must sign this application in Section VII.

4. Other Legal Control: If the applicant has legal control over the property other than a lease agreement, please provide a description on an attached sheet. ☐ Attached ☐ N/A

## III. CLASSIFICATION

**SECTION A - *Quantity***

1. Annual average quantity applied for, in gallons per day (gpd). This quantity should reflect the amount needed six years and ten years hence, or for the remainder of permit duration, if the application is for a modification:

   6 years: 2,428,000 (gpd) 10 years: -- (gpd) Other: 17,500,000 (gpd)

2. Indicate the requested peak monthly pumpage quantity. See Section 3 of the *Basis of Review* for an explanation of this quantity.

   6 years: 5,143,000 (gpd) 10 years: -- (gpd) Other: 17,500,000 (gpd)

**SECTION B - *Water Use***

3. Indicate all that apply. Information Supplements must be filled out for all uses. See Section 3 of the *Basis of Review* for explanations of the use classifications.

   ☐ Public Supply ☐ Recreation or Aesthetic ☐ Agriculture
   ☒ Industrial or Commercial ☐ Mining or Dewatering

4. Indicate the date on which the use of water was initiated or is proposed for initiation (month/day/year): ____________

5. Indicate the quantity and source of any reuse water used by the applicant:
   Annual Average Quantity 1,770,000 gpd; Peak Month Quantity 2,500,000 gpd; Source: City of Bartow

## IV. SITE/WITHDRAWAL INFORMATION

**SECTION A - *Acreage***

1. Number of acres Owned: 8226; Leased: ____________; Serviced ____________.

2. Describe the location of the property contained in this application by Section, Township, Range, 1/4 Section:
   Section ____________, Township ____________, Range ____________, 1/4 Section ____________.

   See WUP 2010944

**SECTION B - *Location Maps***

3. Provide a recent aerial map showing: (a) a north arrow; (b) a scale designation - all maps should have a minimum scale of 1" = 2,000'; (c) landmarks such as roads and political boundaries; (d) property boundaries - include approximate lengths of boundaries in feet; (e) withdrawal point locations - label withdrawal points, indicate the distance from the withdrawal points to the nearest property boundaries in feet, *(If the withdrawal points are located on non-contiguous parcels, provide separate large-scale maps in addition to a large-scale map which includes all parcels); (f) the area serviced or irrigated, *(If the area serviced or irrigated is a distance from the withdrawal locations, provide separate map(s).

   * May require separate or additional maps. See attached Map

4. Use a Map (not necessarily an aerial) or a sketch of the applicant's property and surrounding area to indicate:
   a. Approximate location of other wells not owned by the applicant including domestic wells, irrigation wells, public water supply wells, etc. within the distance set forth in Item 5, Table 1, below. Supplemental locations at a greater distance may be required. No wells within 2640 feet of Wells P-1 and P-2
   b. Location of monitoring wells, including reference numbers.
   c. Wetlands greater than 0.5 acre in size, covering the area within the distance set forth in Item 5, below.
   Substantial off-site drawdown impacts may require additional aerial coverage. Mining applicants requirements differ, and are provided on the Mining and Dewatering Supplemental Form, Form No. WUP-6.

**SECTION C - *Adjacent Property Owners***

5. Submit a listing of the names and mailing addresses of property owners near the property contained in this application, based on the quantity to be withdrawn and the table provided below. You may choose a distance from either your property boundary or your withdrawal point. The District may require additional potentially affected property owners to be submitted.

*Section C, Item 5 continued on Page 3*

*Section C, Item 5 continued from Page 2*

***TABLE 1 - FOR WELL OR MINE PIT WITHDRAWALS OF:***

| Average GPD on an Annual Basis | OR | Maximum GPD During Any Single Day | Provide Information on the Following: |
|---|---|---|---|
| 500,000 gpd but less than 1,000,000 gpd | | More than 5,000,000 but not more than 10,000,000 gpd | All property owners within 1,320' of the well, or within 200' of your property boundary |
| 1,000,000 gpd or greater | | More than 10,000,000 | All property owners within 2,640' of the well, or within 400' of your property boundary |

***TABLE 2 - FOR SURFACE WATER WITHDRAWALS:***

If your withdrawal is from a lake with a surface area of 80 acres or less, list below all riparian owners on the lake or impoundment.

If your withdrawal is from a lake larger than 80 acres, list below all riparian owners in either direction 660' from point where applicant's property intersects the shoreline.

If your withdrawal is from a stream and if the maximum daily average pumpage is less than 5,000,000 gpd, list below all riparian owners 660' upstream and 1,320' downstream from your property boundaries at the shoreline.

If your withdrawal is from a stream and if the maximum daily average pumpage is greater than or equal to 5,000,000 gpd, list below all riparian owners 1,320' upstream and 2,640' downstream from your property boundaries at the shoreline.

| Name | Mailing Address |
|---|---|
| None | |

**SECTION D - *Withdrawal Points***

6. **Groundwater Withdrawals.** Include all wells on property greater than 2 inches in diameter, whether active or inactive, and whether existing or proposed, in the table on the following page:

**TABLE LEGEND:**

***SWFWMD I.D. No.*** - the withdrawal number assigned by the District, if existing.
***Owner I.D. No.*** - the owner's I.D. number.
***Construction Date*** - the approximate date that the withdrawal point became operable.
***Average Withdrawal Rate*** - the total quantity of water to be withdrawn in one year divided by 365, in gpd.
***Peak Monthly Withdrawal Rate*** - the maximum quantity to be withdrawn in a single month, in gpd.
***Maximum Daily Withdrawal Rate*** - the maximum quantity to be withdrawn in any single day.
***Standby*** - refers to status of wells that would not be used unless another well becomes inoperable.
***Cap*** - the well is capped.
***Meter*** - refers to whether a flow meter is installed: if several withdrawals are connected to the same meter. (ganged), indicate by placing a letter character (a,,b, etc.) instead of a check mark, linking those interconnected withdrawals by like characters. If an indirect flow measuring device (e.g. an elapsed time meter, etc.) is used, place an I (indirect) in the space provided.
***Monitor*** - refers to water level or water quality monitors. Indicate the type of monitor by placing an L (Level), Q (Quality), or both in the space provided. The absence of checkmarks or letters indicates active status.
***Mainline Diameter*** - refers to the outside diameter of the main discharge pipe.
***Proposed*** - check if the withdrawal point is proposed rather than existing.

*Section D, continued on Page 4*

*Section D, continued from Page 3*

See WUP 2010944

| I.D. No. SWFWMD | I.D. No. Owner | Casing Diameter | Depth Cased | Total Depth | Constr. Date | Pump Capacity (gpm) | Withdrawal Rate | | Proposed | Status (check): | | | | Mainline Diameter |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Average Annual | Peak Month | | Mon. | Stdby | Cap. | Meter | |
| 1 | P-1 | 20 | 360 | 880 | 2006 | 2500 | 2428000 | 3600000 | x | | | | | 16 |
| 2 | P-2 | 20 | 360 | 880 | 2006 | 2500 | 2428000 | 3600000 | x | | | | | 16 |
| 6 | P-6 | 8 | 300 | 500 | 1998 | 100 | 19000 | 36000 | | | | | | 2 |
| | | | | | | | | | | | | | | |
| | | | | | | | | | | | | | | |

7. Indicate the future use of any capped source: ______________________________

8. Indicate the parameters sampled for any monitor wells listed above: See Groundwater Monitor. Plan

9. **Surface Water Withdrawals** - See the Groundwater withdrawal section above for explanation of most terms. Source name is the name of a lake, stream or other waterbody.

See Attached Table A.

| I.D. No. SWFWMD | I.D. No. Owner | Source Name | Lake Acreage | Intake Diameter | Pump Capacity (gpm) | Withdrawal Rate | | Proposed | Status (check): | | | Mainline Diameter |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Average Annual | Peak Month | | Active | Stdby | Metered | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |
| | | | | | | | | | | | | |

10. **Other Sources.** Describe any other sources of water, such as from utilities, treated waste water effluent, etc. List annual average and peak month quantities for each additional source: ______________________________

City of Bartow, ALCOA, Tiger Bay Cogen. Plant

## V. IMPACTS

Are you aware of any adverse impacts that your withdrawals have or may have on other water users, off-site land uses, the water resources, or environmental features? If so, provide a detailed explanation of the impact and your plans to deal with it.

None Anticipated ☒ Explanation Attached ☐

## VI. HYDROGEOLOGY

Provide any information available on regional and site-specific hydrogeology, including aquifer characteristics, for all aquifers existing in the area of your withdrawals. Provide documentation and references in support of this information. If you do not have such information, hydrogeologic testing may be required either as additional information in support of your application, as a condition of the permit, or both. The District may use appropriate regional data in lieu of or in addition to submitted information to assess the impacts of your withdrawals. New hydrogeologic testing should follow the guidelines of Part C, *Permit Information Manual.*

See Site Certification Application

## VII. APPLICANT CERTIFICATION

I hereby certify that the information contained herein is true and accurate and that I have legal authority to undertake the activities described herein and execute this application.

| | |
|---|---|
| ________________________ | 12/18/02 |
| Applicant Signature | Date |

I hereby certify that the applicant has sufficient legal control of the property described in this application.

| | |
|---|---|
| ________________________ | __________ |
| Property Owner (if other than applicant) | Date |

## *APPLICANT CHECK LIST:*

Attachments requested in support of this application:

| | | *Attached* | *N/A* |
|---|---|---|---|
| 1. | (Section II-1) Copy of Legal Description | ☐ | ☒ |
| 2. | (Section II-2) Copy of Current Lease | ☐ | ☒ |
| 3. | (Section II-3) Description of Other Legal Property Control | ☐ | ☒ |
| 4. | (Section IV-3) Aerial Map | ☒ | ☐ |
| 5. | (Section IV-4) Site Map | ☒ | ☐ |
| 6. | (Section IV-5) Adjacent Property Owners | ☐ | ☒ |
| 7. | (Section VI) Hydrologic Information | ☐ | ☒ |
| 8. | Appropriate Supplemental Form | ☒ | ☐ |

**TABLE A. WITHDRAWAL INFORMATION FROM COOLING AND WATERCROP AREAS AT HINES ENERGY COMPLEX**

| Water Source | Water Acres | Pipe Diam. | Pump Capacity | Remarks |
|---|---|---|---|---|
| Cooling Pond | 722 | 72” | 60,000 gpm | Each Power Block has 2 pumps |
| Plant Island Ditch | 5 | 18” | 5,000 gpm | Two pumps |
| East Side Water Crop | 20 | 18” | 5,000 gpm | Temporary pump |
| N-11B | 5 | 18” | 5,000 gpm | Temporary pump |
| SA-8 | 20 | 12” | 5,000 gpm | Temporary pump |
| Triangle Lakes | 60 | 18” | 3,200 gpm | Currently being installed |

# WATER USE PERMIT APPLICATION SUPPLEMENTAL FORM

*SOUTHWEST FLORIDA WATER MANAGEMENT DISTRICT*

2379 BROAD STREET • BROOKSVILLE, FL 34609-6899 • (352) 796-7211 or FLORIDA WATS 1 (800) 423-1476

# INDUSTRIAL OR COMMERCIAL

ANSWER ALL QUESTIONS. IF A QUESTION IS NOT APPLICABLE, ENTER N/A. IF MORE SPACE IS NEEDED, ATTACH ADDITIONAL SHEETS AND REFER TO THE APPLICATION QUESTION NUMBER. PROVIDE DOCUMENTATION AND REFERENCES WHERE APPROPRIATE. IF THERE ARE OTHER USES, COMPLETE THE APPROPRIATE SUPPLEMENTAL FORM (S). THIS INFORMATION IS REQUESTED IN ACCORDANCE WITH RULES 40D-2.101 AND 40D-2.301, FLORIDA ADMINISTRATIVE CODE.

***NOTE:*** IF PROCESSING OF MATERIALS IS ASSOCIATED WITH MINING OR DEWATERING, USE THE **MINING AND DEWATERING SUPPLEMENTAL FORM, WUP FORM NO 6,** AND INCLUDE THE INDUSTRIAL/COMMERCIAL USES ON THAT FORM.

*AN ASTERISK IDENTIFIES ITEMS TO BE INDICATED ON SITE MAP; YOU MAY USE THE MAP REQUESTED IN ITEM IV, SECTION B OF THE APPLICATION FORM.

**PLEASE SUBMIT *THREE COPIES* OF THIS SUPPLEMENTAL FORM ALONG WITH YOUR APPLICATION, DRAWINGS, CALCULATIONS, ETC.**

## I. GENERAL INFORMATION

APPLICANT: Progress Energy Hines Energy Complex WUP No. (If Existing): 2012367 and 2010944
(Same as shown on WUP application)

## II. SITE INFORMATION

**SECTION A - *Fire Flow***

1. Describe fire flow and standby capacity (identify withdrawal points and when they would be used).

**SECTION B - *Existing Wellfields***

Describe the existing wellfield operation schedule, if applicable. Include in the description those wells that are primary, secondary, stand-by, and the well rotation schedule, if any. Description Attached ☐ N/A ☒

**SECTION C - *Surface Water Management System***

Is a surface water management system proposed? Yes ☐ No ☒ Existing? Yes ☐ Permit No. exempt No ☐

If so, an evaluation of the impact of the proposed withdrawal on the surface water management system, and conversely, the impact of the surface water management system on the withdrawal and water availability at the project site must be submitted.

**SECTION D - *Discharge/Recirculation***

Identify the following items on a map or maps: 1. Discharge points; 2. Recirculation or settling ponds.

Number the ponds, and list the acreage of each pond: See Table A

| Pond No. | Acreage |
|---|---|
| | |
| | |
| | |

## III. WATER USE

**SECTION A -** ***Annual Average Quantities in gallons per day (gpd)***

| | Present | Projected 6-Year | Projected 10-Year |
|---|---|---|---|
| 1. Potable and sanitary needs | 19,000 | 19,000 | 19,000 |
| 2. Lawn and landscape irrigation | 0 | 0 | 0 |
| 3. Outside use (washing, maintenance) | 0 | 0 | 0 |
| 4. Fire protection (testing, maintenance) | 0 | 0 | 0 |

5. Provide a Water Balance diagram, indicating all water sources (ground water from wells, ground water from water table dewatering or drainage, surface water, rainfall, recycled water, etc.), the amount of water entering and leaving each step in the process, all water losses (e.g. evaporation, product moisture, steam losses, waste-material entrainment, off-site discharge, recycle, etc.), and the final disposition of water. These diagrams should be based on the annual average daily quantity and the peak monthly quantity. All flows must be in units of gallons per day, and the total of all sources must equal the total of all losses. See Fig. 3.5.1-3 and Fig. 3.5.1-4

| | Present | 6-Year | 10-Year |
|---|---|---|---|
| 6. **Total Water Demand** (Total Items 1-5) | 19000 | 2428000 | 17500000 |
| 7. Provide the percentage of unaccounted water (total system throughout minus all accounted and in-plant uses): | 0 | 0 | 0 |
| 8. Population served (works/visitors): | 30 | 40 | 50 |

**SECTION B -** ***Lawn and Landscape Irrigation***

If any of the projected water use will be for irrigation of lawns, landscaping of recreational areas, respond to items 1 through 5 below; if not, please check N/A. N/A ☒

If these quantities are greater than 100,000 gpd annual average, you must fill out the Recreational Supplemental Information Form, WUP 8.

1. Acres to be irrigated ____
2. Type(s) of vegetation to be irrigated ____
3. Irrigation method ____
4. Approximate peak monthly water use ____
5. Approximate annual average water use ____
6. Show irrigated area(s) on map.*

**SECTION C -** ***Peak Month Quantity***

Provide the peak month quantity needed at present, in 6 years, and in 10 years. Provide calculations supporting these quantities.

| | Present | 6 year | 10 year |
|---|---|---|---|
| 9. **Total peak month quantity (gpd)** | 35000 | 5143000 | 17500000 |

## IV. DISPOSAL

**SECTION A -** ***Methods of Disposal***

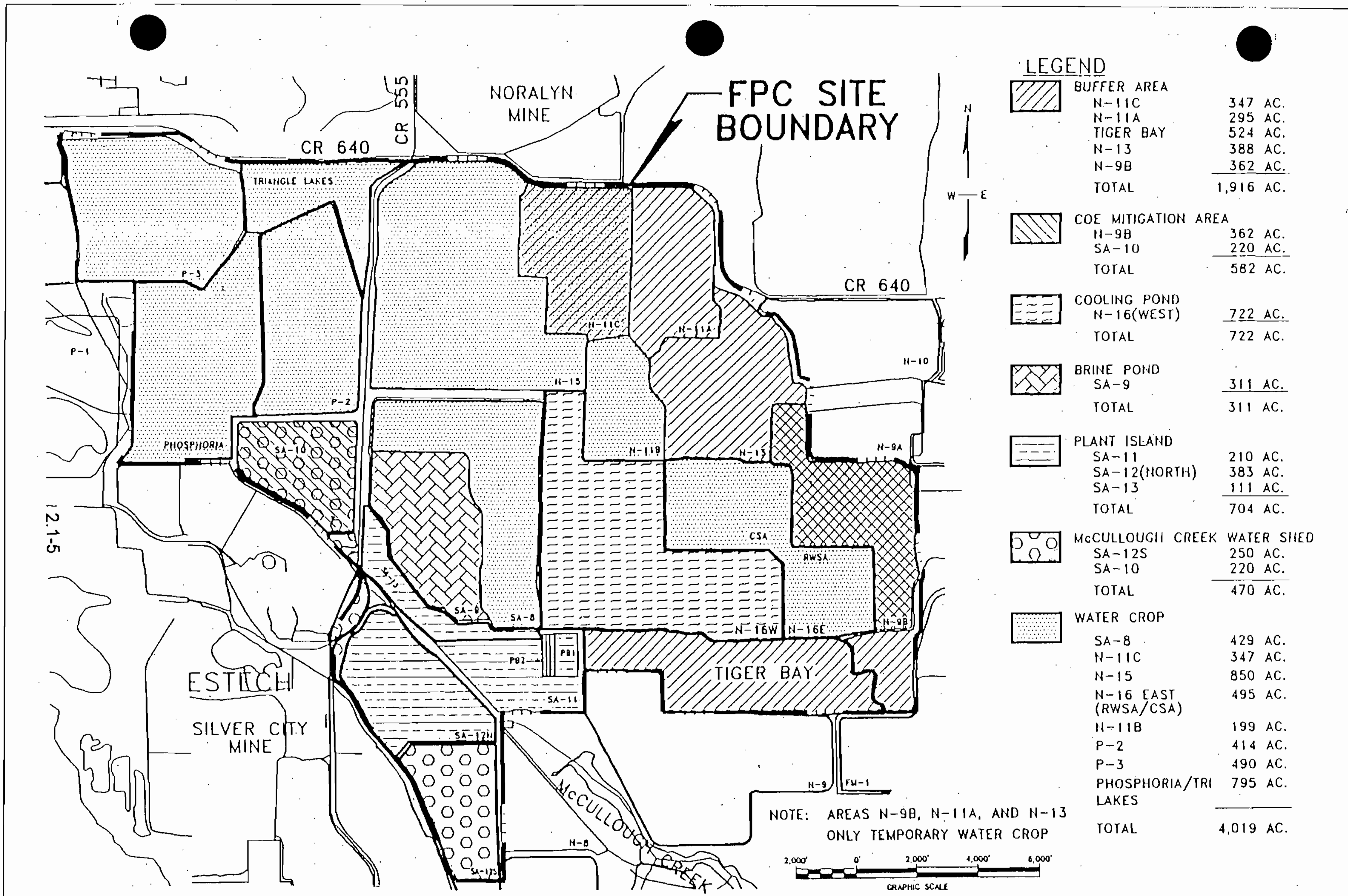
SPECIFY THE PERCENTAGE FOR EACH, TO TOTAL 100%:

1. Individual septic tank ____ %
2. Percolation pond ____ %
3. Offsite discharge ____ %
4. Spray irrigation ____ %
5. Other 100 % Specify Onsite Treatment Plant
6. Discharge to other location ____ % Name ____
   NPDES, DER Discharge Permit Nos. ____
7. Discharge to other location ____ % Name ____
   NPDES, DER Discharge Permit Nos. ____

**TOTAL** 100 %

## V. WATER CONSERVATION

1. Attach a description of water conservation practices currently employed or planned. If planned, include an estimated time frame for implementation. ☐ Attached
2. Include plans to recycle waste water, and provide present and future quantities. ☐ Attached






Florida Power CORPORATION
Hines Energy Complex

**FIGURE 2.1.2-1**
**HINES ENERGY COMPLEX 1000 MW SITE PLAN**

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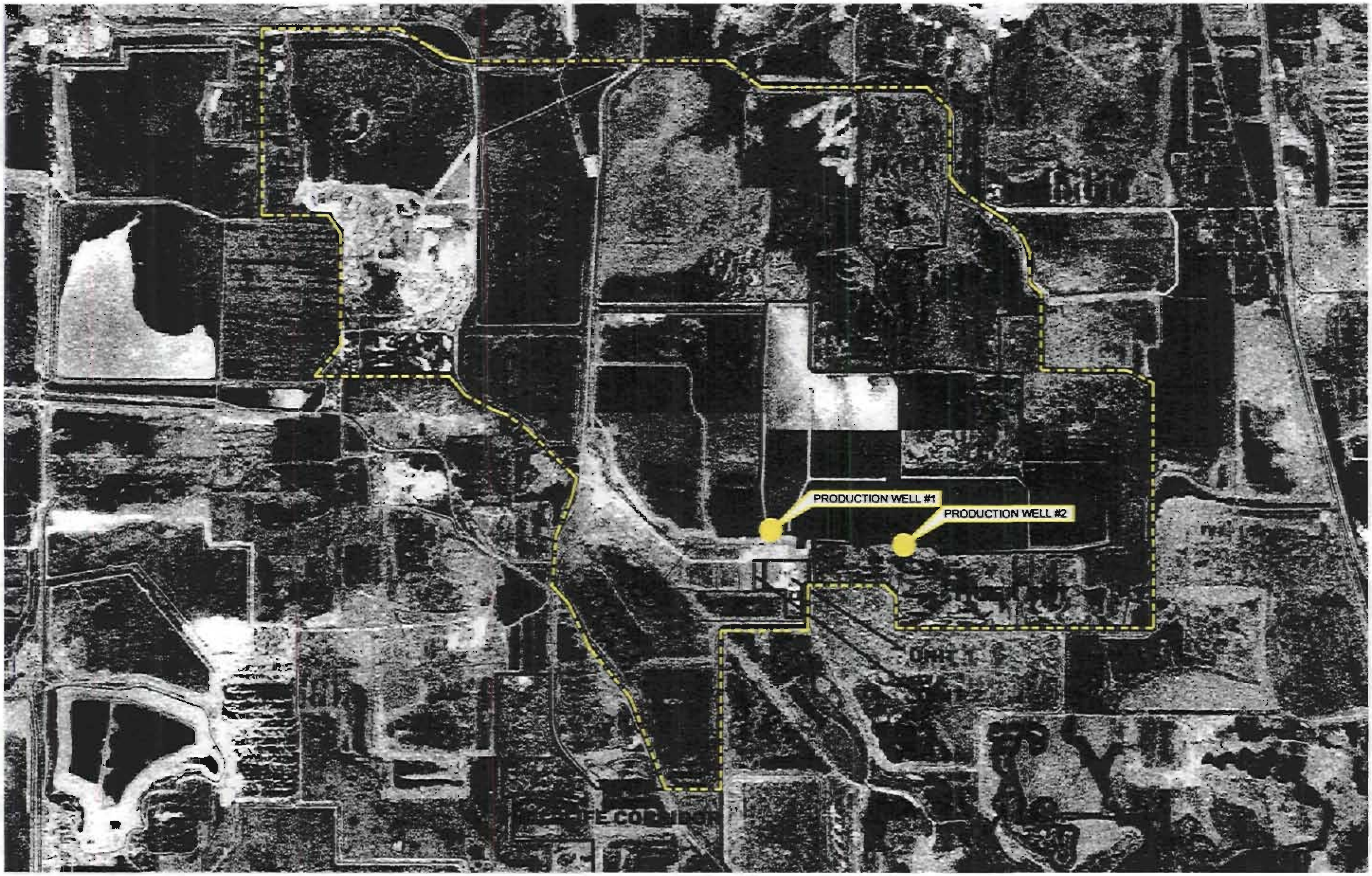


0 1 Miles

Florida Power

Hines Energy Complex

GROUNDWATER WELL LOCATIONS

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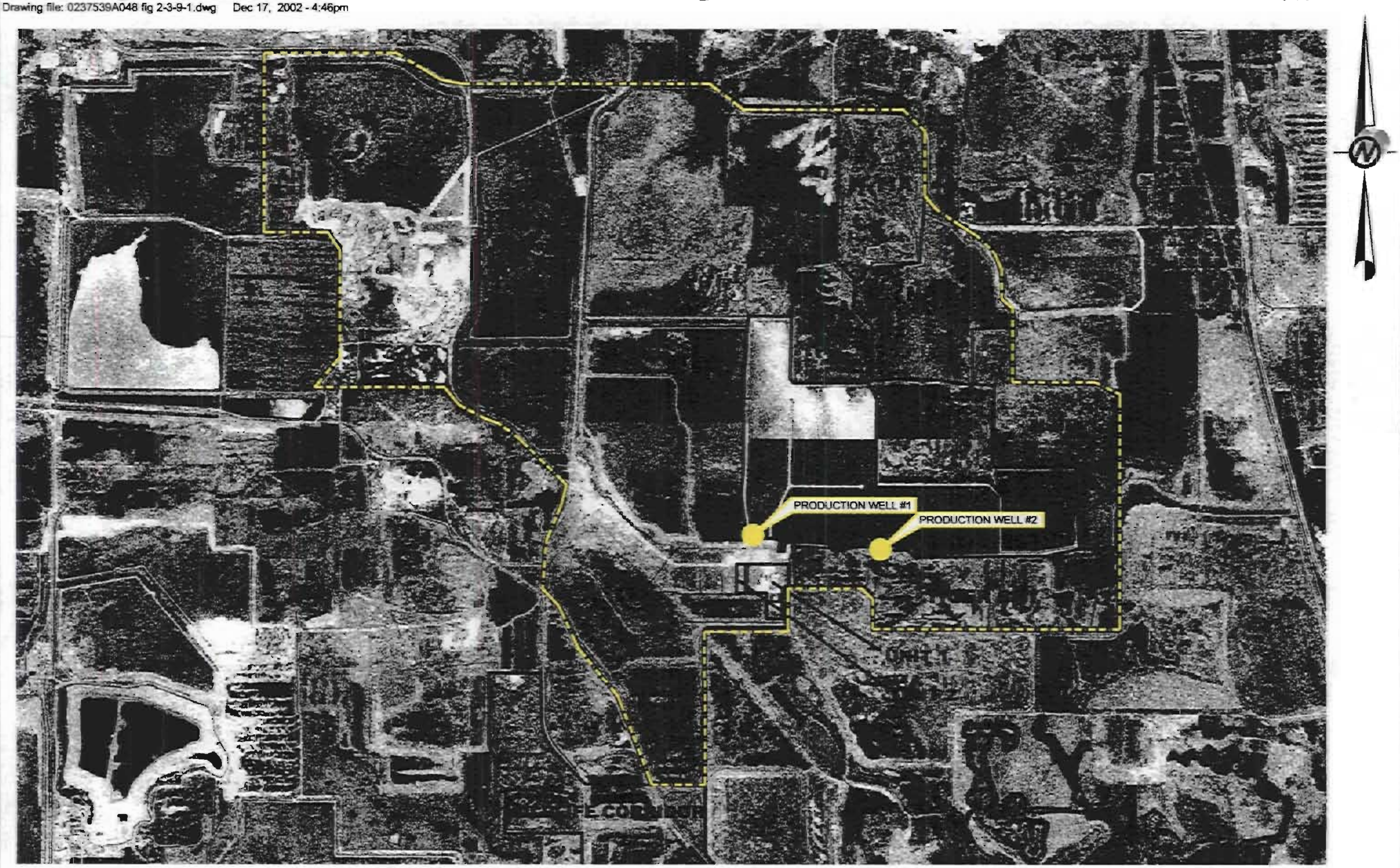


Florida Power
Hines Energy Complex

0 1 Miles

GROUNDWATER WELL LOCATIONS

Ardaman & Associates, Inc.

Geotechnical, Environmental and
Materials Consultants

September 9, 2002
File No.: 02-55-9638

Mr. Randy Melton
Florida Power Corporation
7700 CR 555
Bartow, Florida 33830

Subject: Evaluation of Seepage Losses from N-16, Cooling Pond
Hines Energy Center, Polk County, Florida

Dear Mr. Melton:

As authorized on August 26, 2002, Ardaman & Associates, Inc. has completed seepage and water loss analyses for the N-16 cooling pond and ESA at the Hines Energy Center. This report presents the data used and the results of our analyses.

**Background**

As we understand it, expansion plans at the Hines Energy Center make it necessary to improve the estimate of water losses due to seepage from the cooling pond system at the plant. Because Ardaman & Associates, Inc. has been tracking piezometer data for Florida Power since August of 1996 as well as conducting annual inspections of the dams forming the cooling pond and other reservoirs, we have the background information required for such analyses.

The cooling pond was constructed within an area mined for phosphate matrix. It is typical for the mining operations to trench into the base limestone and bed clay materials for drainage. If this was done in N-16, it can caused increased base seepage due to the interconnection of the mined area with the limestone aquifer systems. Also, N-16 was used for deposition of clay washed out of the phosphate matrix during beneficiation. This clay can act to seal the bottom of the area. For example, N-15 to the northwest of N-16 was used a s a clay storage area, so base seepage from this area would be minimal.

**Design Information**

Cooling Pond N-16 consists of a series of dams that separate it from other cells on site. Each of these sections has been grouped based on the section geometry and is identified with a letter. The following table presents the section number, its relative location and pertinent information regarding each section.

3925 Coconut Palm Drive, Suite 115, Tampa, Florida 33619 Phone (813) 620-3389 FAX (813) 628-4008
Offices in: Bartow, Cocoa, Fort Lauderdale, Fort Myers, Miami, Orlando, Port Charlotte, Port St. Lucie, Sarasota, Tallahassee, Tampa, W. Palm Beach

| Section ID | Location | Remarks |
|---|---|---|
| J-1 | Southwest corner of N-16 | Location of plant outflow |
| J-2 | South boundary of N-16 | Separates N-16 from Tiger Bay |
| J-3 | South portion of ESA | Separates ESA from Tiger Bay |
| K | Northeast corner of N-16 | Separates N-16 from N-11B |
| L | North boundary of N-16 | Separates N-16 from N-15 |
| M | Northwest corner of N-16 | Separates N-16 from Recirculation Ditch |
| N | Western boundary of N-16 | Separates N-16 from SA-8 |
| Q | Northeastern boundary of N-16 | Separates N-16 from ESA |
| R | Northern boundary of N-16 | Separates N-16 from ESA |
| S | Eastern Boundary of N-16 | Separates N-16 from ESA |

The attached Figure 1 shows the layout of the N-16 cooling pond and the ESA (Effluent Storage Area).

A portion of the data for our analyses was obtained from a series of reports prepared by Dames & Moore. This data includes information on section geometry, soil types used in the sections, and design soil properties. A series of piezometers were also installed in the N-16 dams. After installation, sensitivity tests were run in each piezometer. These tests provided permeability values for use in our analyses.

Also, as stated earlier, we have been monitoring the water levels in the piezometers since 1996. This data was used to estimate the phreatic surface through the dams.

Data from 4 wells installed into the Hawthorn formation near N-16 (FMW-1, IMW-2, IMW-3, and IMW-4) were provided by Gus Schaeffer of Florida Power Corporation. These wells provided information regarding water levels in the underlying bed clay and limestone under the dams.

**Analyses**

Based on our review of the cooling pond configuration, it was determined that not all sections result in seepage out of the pond. The water levels in SA-8 is about +163 feet. This is slightly above the water level in N-16 (currently about +161 feet). The water level in N-15 (about +165) is also above the level in N-16. Therefore, the seepage out of N-16 from sections L, M, and N is negligible. Also, the water level in Tiger Bay (+148 feet) is at or above the level in the ESA (145 feet), resulting in minimal seepage loss from the ESA into Tiger Bay. At section J-1, the downstream ground surface is at the same elevation as the top of the dam and this section is relatively short. Therefore, seepage losses from this section were assumed to be minimal.

*Section K*

Figure 2 presents the generalized geometry, soil types, and water levels used for the analyses of section K. Also included on the figure are the data obtained from the Hawthorne well. The line near the bottom of the figure is the potentiometric surface of the Upper Floridan Aquifer. This is the expected water level for the limestone formation. It should be noted that the water level seen on the deep well corresponds to the water levels seen in the shallow well. This indicates base seepage and a direct connection between the screen interval of the well and the seepage through the dam.

Using the construction data from Dames & Moore, the water levels in the piezometers, the dam length, and the permeability test results, an estimated seepage quantity was calculated. Using an average pond elevation of +160.85 feet, a seepage quantity of 105 thousand gallons per day was calculated. At maximum pond level (+165 feet), this value raises to 132 thousand gallons per day.

*Section J-2*

Figure 3 presents the generalized geometry, soil types, and water levels used for the analyses of section J-2. Also included on the figure are the data obtained from the Hawthorne well. The line near the bottom of the figure is the potentiometric surface of the Upper Floridan Aquifer. This is the expected water level for the limestone formation. It should be noted that the water level seen on the deep well corresponds to the water levels seen in the shallow wells. This indicates base seepage and a direct connection between the screen interval of the well and the seepage through the dam.

Using the construction data from Dames & Moore, the water levels in the piezometers, the dam length, and the permeability test results, an estimated seepage quantity was calculated. Using an average pond elevation of +160.85 feet, a seepage quantity of 136 thousand gallons per day was calculated. At maximum pond level (+165 feet), this value raises to 180 thousand gallons per day.

*Sections Q, R, and S*

Figure 4 presents the generalized geometry, soil types, and water levels used for the analyses of sections Q, R, and S.

Using the construction data from Dames & Moore, the water levels in the piezometers, the dam length, and the permeability test results, an estimated seepage quantity was calculated. Using an average pond elevation of +160.85 feet, a seepage quantity of 166 thousand gallons per day was calculated. At maximum pond level (+165 feet), this value raises to 211 thousand gallons per day.

Combining the lateral seepage from the three areas results in a total of about 406 to 523 thousand gallons per day. This estimate does not include any losses from the ESA to the north or east.

*Base Seepage*

As mentioned above, the deep piezometers in the Hawthorne show water levels at the same levels as the shallow piezometers in the dams. This confirms that base seepage is occurring. The very deep well, FMW-1, is about 220 feet deep. Data from this well has not been plotted on the attached figures since it is away from N-16. However, based on the well completion report, the post development water level was at elevation +163.06 feet, only 3 feet below the ground surface. This water level generally corresponds to the water level in N-16. This further shows that seepage is occurring from N-16 into the intermediate aquifer.

In order to estimate base seepage, we utilized a vertical permeability of $1 \times 10^{-7}$ cm/sec for the upper bed clays. A head difference between the pond levels and the total head of the Upper Floridan Aquifer was also used in the calculations. Assuming an area of 732 acres for N-16, the base seepage quantity is estimated at 351 thousand gallons per day. For the 442 acre ESA, about 181 thousand gallons per day was estimated. Therefore, the total base seepage for N-16 and the ESA is 532 thousand gallons per day.

*Evaporation/Transpiration*

Data on rainfall is included with each set of piezometer monitor data. Our review of the rainfall data indicates that the average rainfall between May 2, 1998 and August 24, 2002 was 46.67 inches. This value is site specific since on-site rain gauges are used to measure accumulated rainfall between each set of piezometer readings.. Typical evaporation losses are 50 inches per year. However, the loss from N-16 may be greater due to the heat energy from the plant present in the cooling water. Using the two averages, there is a net loss of 3.24 inches per year. This translates to 0.009 inches per day. The total combined open water area of N-16 was estimated at 732 acres while the ESA has about 210 acres. Using the open water area, the total evaporation loss is estimated at 230 thousand gallons per day.

**Conclusions**

Combining the losses from lateral seepage and base seepage results in a range of total seepage loss from 938 to 1,055 thousand gallons per day. The amount of water loss from evaporation has not been included in this total due to the amount of variability resulting from temperature and composition factors beyond the scope of these analyses.

We appreciate the opportunity to provide our services on this important project. If you have any questions on the data or analyses, please contact the undersigned at your convenience.

Very truly yours,

Ardaman & Associates, Inc.

Philip J. Erbland, P.E.
Project Engineer
Florida License No. 52621

Ross T. McGillivray, PE
Chief Engineer, Tampa Branch
Florida License No. 17920

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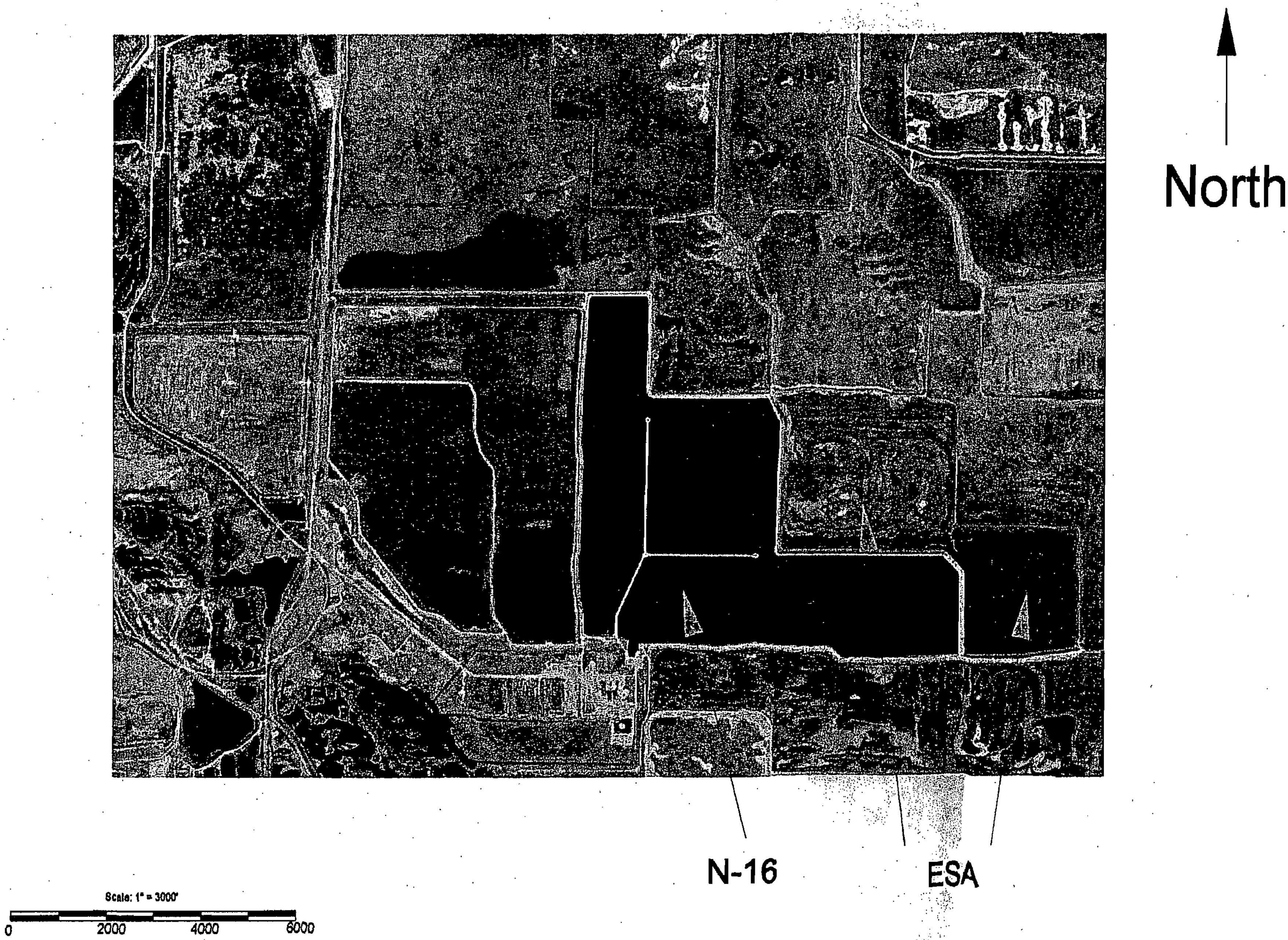
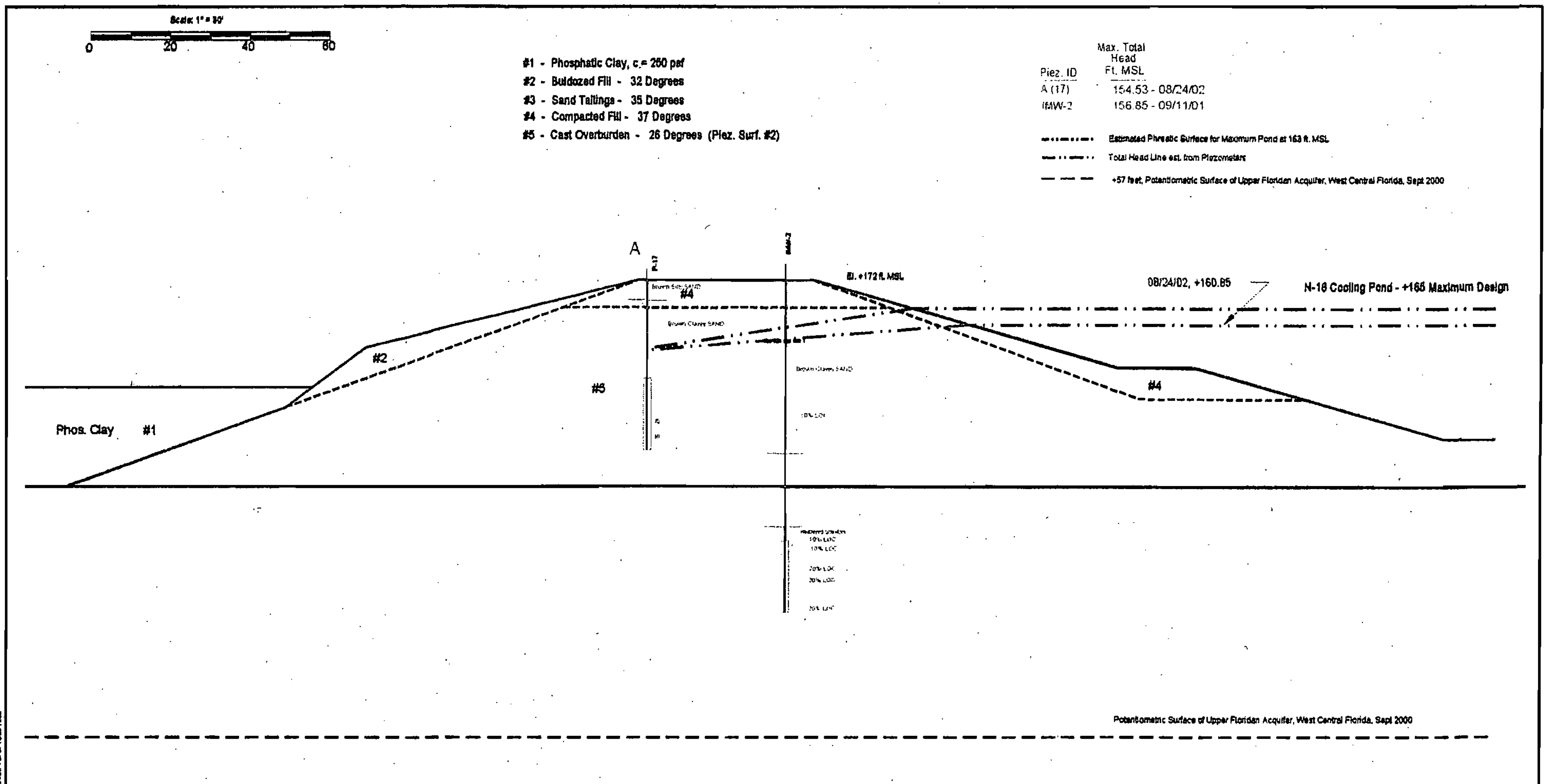



| | | | | | |
|---|---|---|---|---|---|
| DRAWN BY: PJE | CHECKED BY: | DATE: 04-09-02 | N-16 Cooling Pond | Ardaman & Associates, Inc. | FIGURE NO. |
| FILE NO. 02-8636 | APPROVED BY: Ross T. McGillivray, PE | | Florida Power Corporation Hines Energy Complex - Polk Co., FL | Consulting Engineers in Soils, Hydrogeology, Foundations, and Materials Testing | 1 |

PJE\ 2002 \ 02-8643 \ Figure 1a.dc




| | | | |
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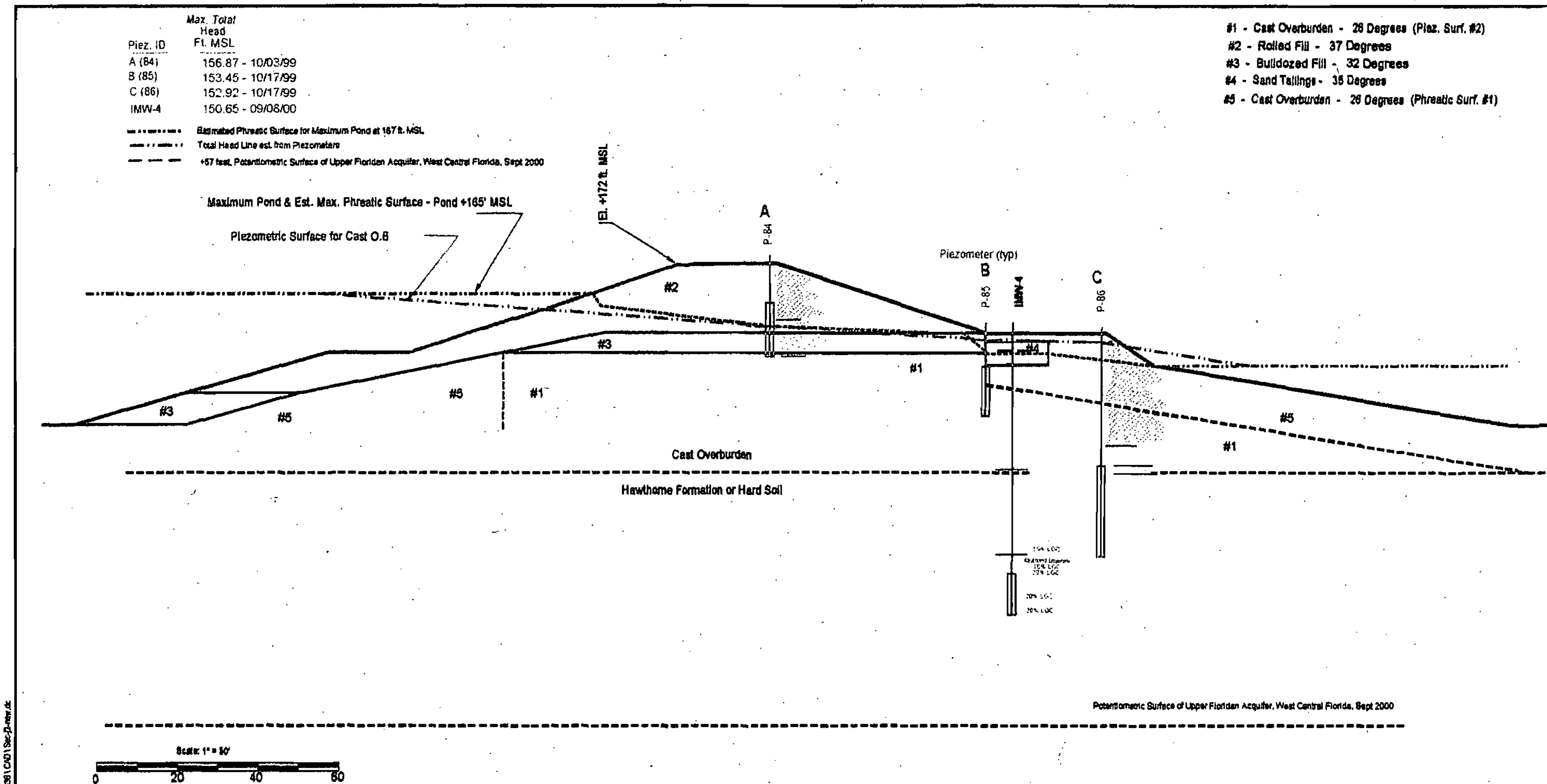
| DRAWN BY: PJE | CHECKED BY: | DATE: 08-26-2002 | |
| FILE NO. 02-55-9638 | APPROVED BY: Ross T. McGillivray, PE | | |

**Section "K" - N-16 Cooling Pond**

**Floirda Power Corporation Hines Energy Complex - Polk Co., FL**

Ardaman & Associates, Inc.
Consulting Engineers in Soils, Hydrogeology, Foundations, and Materials Testing

FIGURE NO. 2



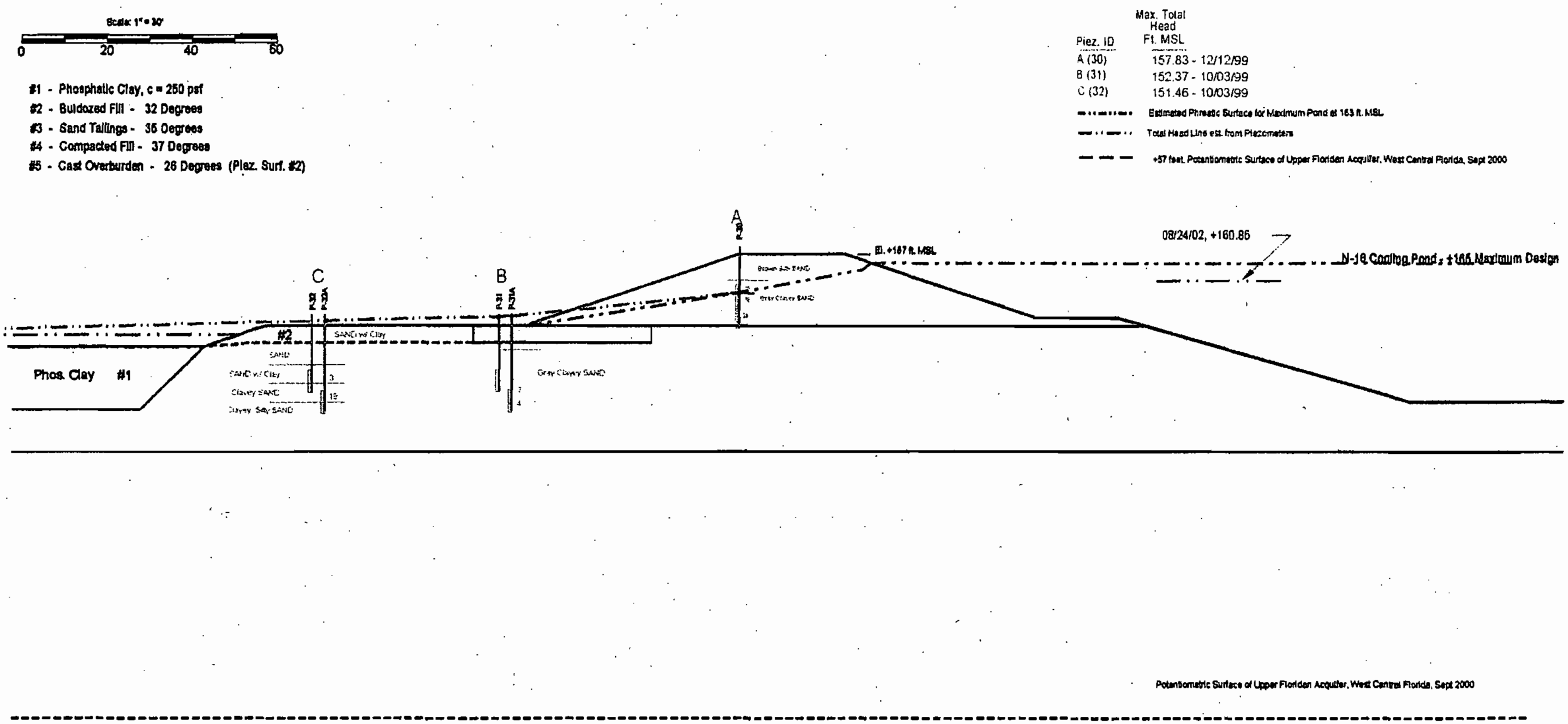

| | | | |
|---|---|---|---|
| DRAWN BY: RTM/PJE | CHECKED BY: | DATE: 08/27/02 | |
| FILE NO. 02-9838 | APPROVED BY: Ross T. McGillivray, PE | | |

**Section "J-2" - N-16 Cooling Pond Dam Cross Section**

**Florida Power Hines Energy Complex - CR 555, Polk County, Florida**

Ardaman & Associates, Inc.
Consulting Engineers in Soils, Hydrogeology, Foundations, and Materials Testing

FIGURE NO. 3



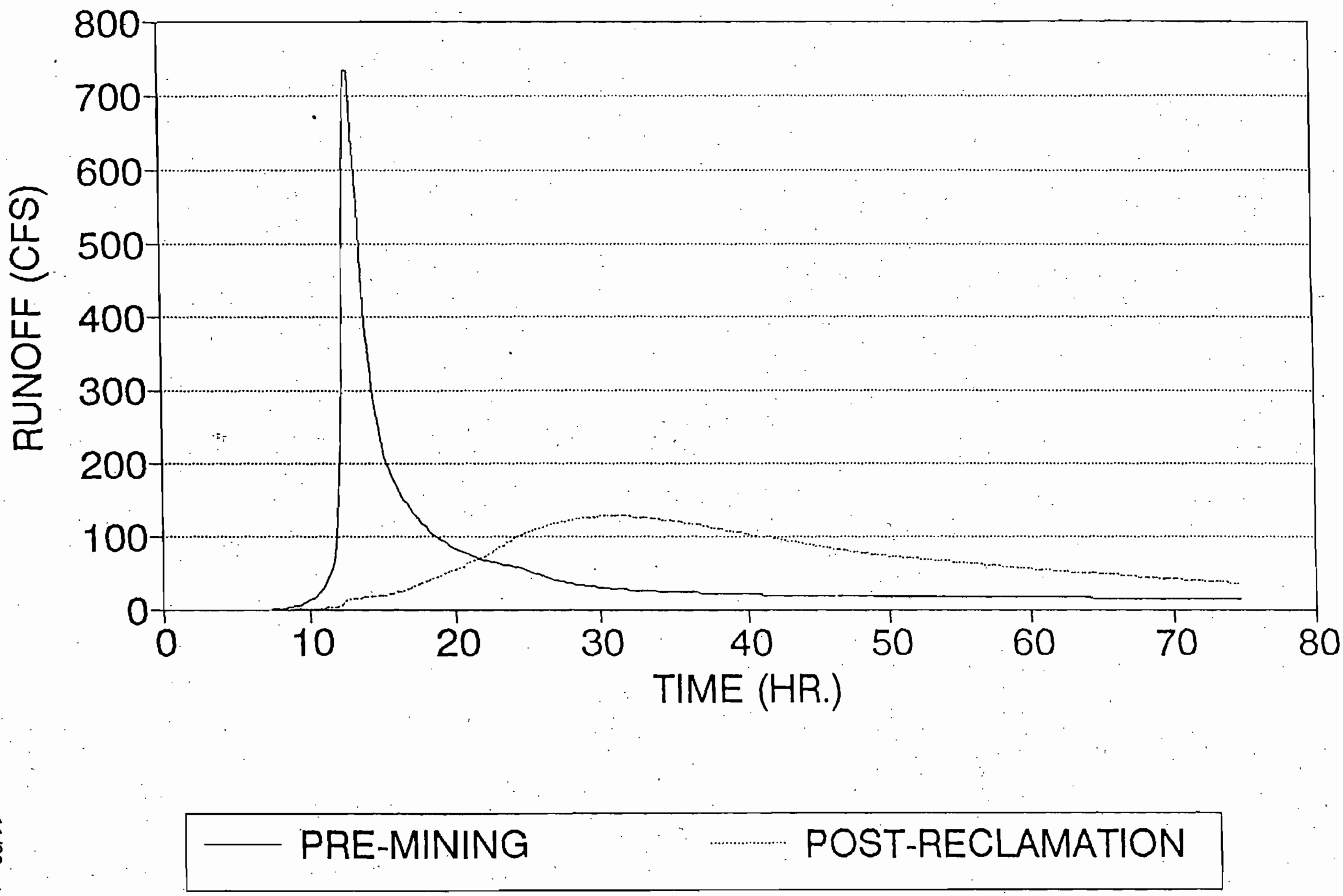

| | | | | | |
|---|---|---|---|---|---|
| DRAWN BY: RTM/PJE | CHECKED BY: | DATE: 08/27/02 | Sections "Q", "R", and "S" - N-16 Cooling Pond | Ardaman & Associates, Inc. | FIGURE NO. |
| FILE NO. 02-6638 | APPROVED BY: Ross T. McGillivray, PE | | Florida Power Corporation Hines Energy Complex - Polk Co., FL | Consulting Engineers in Soils, Hydrogeology, Foundations, and Materials Testing | 4 |

# HINES COOLING POND DATA

| Month | BARTOW avg MGD | Rainfall inches | POND Level ft | Water Crop AF | POND TEMP oF |
|---|---|---|---|---|---|
| Jan-98 | | 4.49 | | | |
| Feb-98 | 2.33 | 10.67 | | | |
| Mar-98 | 2.33 | 10.74 | 157.20 | | |
| Apr-98 | 1.92 | 0.78 | 157.20 | 0 | |
| May-98 | 1.95 | 1.42 | 157.50 | 0 | |
| Jun-98 | 1.76 | 3.76 | 157.40 | 0 | |
| Jul-98 | 1.94 | 11.01 | 158.68 | 0 | |
| Aug-98 | 1.92 | 6.35 | 158.93 | 0 | |
| Sep-98 | 1.95 | 19.93 | 160.48 | 0 | |
| Oct-98 | 1.77 | 1.06 | 160.77 | 0 | |
| Nov-98 | 1.57 | 3.29 | 161.00 | 0 | |
| Dec-98 | 1.53 | 2.63 | 160.94 | 0 | 66 |
| Jan-99 | 1.61 | 2.19 | 161.00 | 0 | 65 |
| Feb-99 | 1.78 | 0.65 | 161.00 | 0 | 64 |
| Mar-99 | 1.7 | 0.53 | 160.78 | 0 | 68 |
| Apr-99 | 1.63 | 2.32 | 160.63 | 0 | 76 |
| May-99 | 1.48 | 4.98 | 160.60 | 0 | 81 |
| Jun-99 | 1.5 | 11.2 | 161.15 | 0 | 82 |
| Jul-99 | 1.69 | 4.05 | 161.05 | 0 | 86 |
| Aug-99 | 2.22 | 7.19 | 161.07 | 0 | 86 |
| Sep-99 | 2.24 | 9.33 | 161.22 | 0 | 80 |
| Oct-99 | 2.33 | 2.42 | 161.30 | 0 | 72 |
| Nov-99 | 2.13 | 2.68 | 161.10 | 0 | 58 |
| Dec-99 | 1.95 | 2.05 | 161.02 | 0 | 60 |
| Jan-00 | 1.88 | 0.88 | 161.00 | 0 | 60 |
| Feb-00 | 1.82 | 0.3 | 160.90 | 0 | 67 |
| Mar-00 | 1.8 | 0.82 | 160.80 | 0 | 75 |
| Apr-00 | 1.62 | 1.12 | 160.70 | 0 | 75 |
| May-00 | 1.54 | 1.08 | 160.28 | 0 | 80 |
| Jun-00 | 1.45 | 6.91 | 160.73 | 0 | 80 |
| Jul-00 | 1.51 | 4.7 | 160.85 | 135 | 83 |
| Aug-00 | 1.58 | 5.03 | 160.90 | 0 | 84 |
| Sep-00 | 1.66 | 5.23 | 160.48 | 0 | 81 |
| Oct-00 | 1.6 | 0.31 | 160.06 | 441 | 73 |
| Nov-00 | 1.7 | 0.63 | 160.00 | 249 | 63 |
| Dec-00 | 1.75 | 0.47 | 159.85 | 192 | 58 |
| Jan-01 | 1.65 | 0.62 | 159.90 | 0 | 56 |
| Feb-01 | 1.71 | 0 | 159.80 | 0 | 67 |
| Mar-01 | 1.64 | 6.23 | 159.70 | 0 | 68 |
| Apr-01 | 1.61 | 0.2 | 159.75 | 0 | 70 |
| May-01 | 1.61 | 2.72 | 159.20 | 0 | 80 |
| Jun-01 | 1.61 | 10.76 | 159.75 | 200 | 82 |
| Jul-01 | 1.63 | 7.98 | 160.15 | 500 | 83 |
| Aug-01 | 1.65 | 5.55 | 160.30 | 300 | 86 |
| Sep-01 | 1.71 | 13.28 | 160.60 | 0 | 79 |

| | | | | | |
|---|---|---|---|---|---|
| Oct-01 | 1.73 | 0.83 | 160.40 | 0 | 70 |
| Nov-01 | 1.76 | 0.32 | 160.00 | 0 | 68 |
| Dec-01 | 1.72 | 0.85 | 159.98 | 0 | 65 |
| Jan-02 | 1.75 | 1.58 | 160.00 | 0 | 71 |
| Feb-02 | 1.76 | 6.19 | 159.70 | 0 | 62 |
| Mar-02 | 1.78 | 0.29 | 159.60 | 0 | 74 |
| Apr-02 | 1.79 | 2.65 | 159.20 | 0 | 76 |
| May-02 | 1.8 | 4.34 | 159.50 | 460 | 79 |

# McCULLOUGH CREEK
## 25 YEAR STORM EVENT POINT A




SR/SWFWMD

161

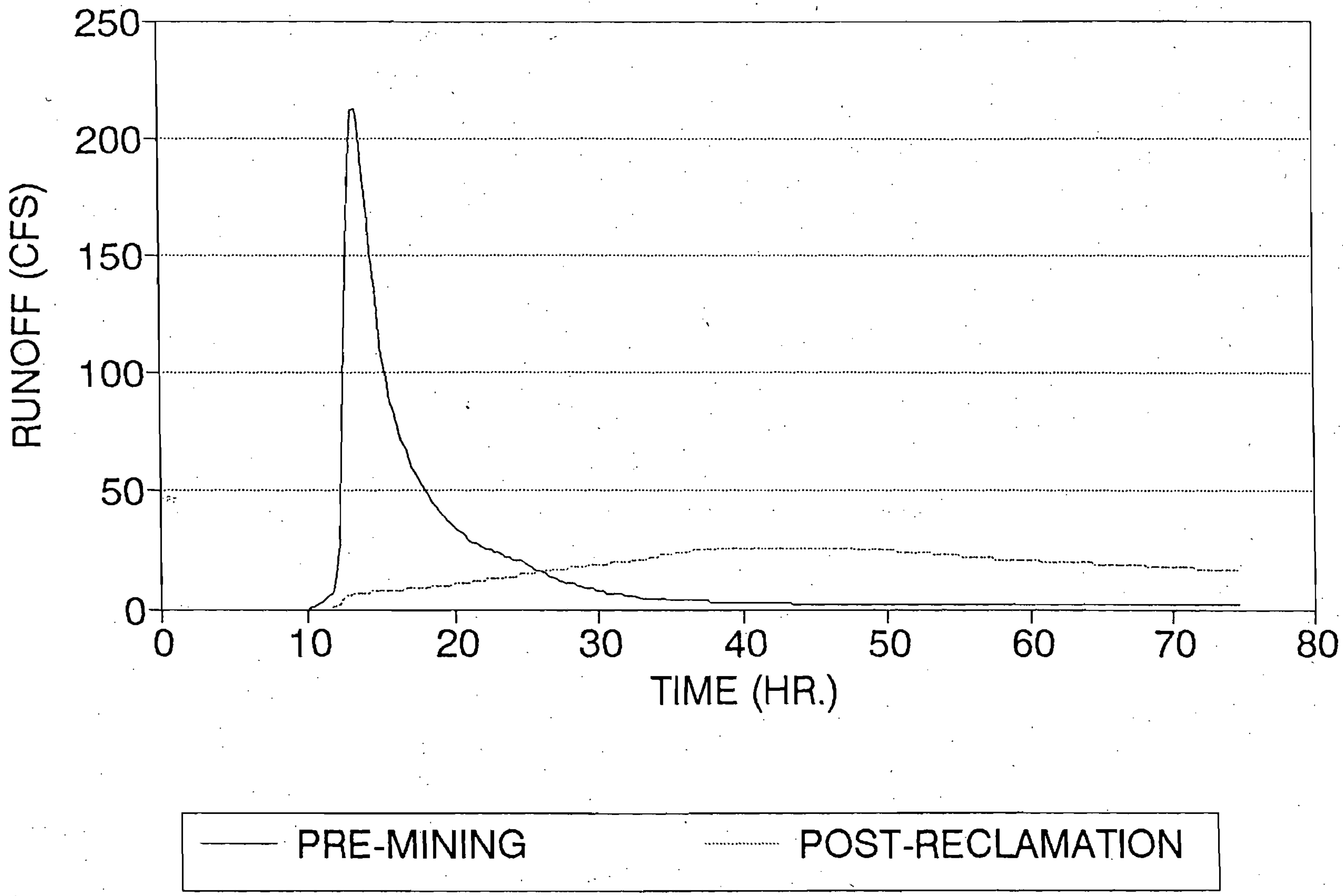
11/92

FPC Polk County Site

EXHIBIT WMD-33B

# McCULLOUGH CREEK

## MEAN ANNUAL STORM POINT A

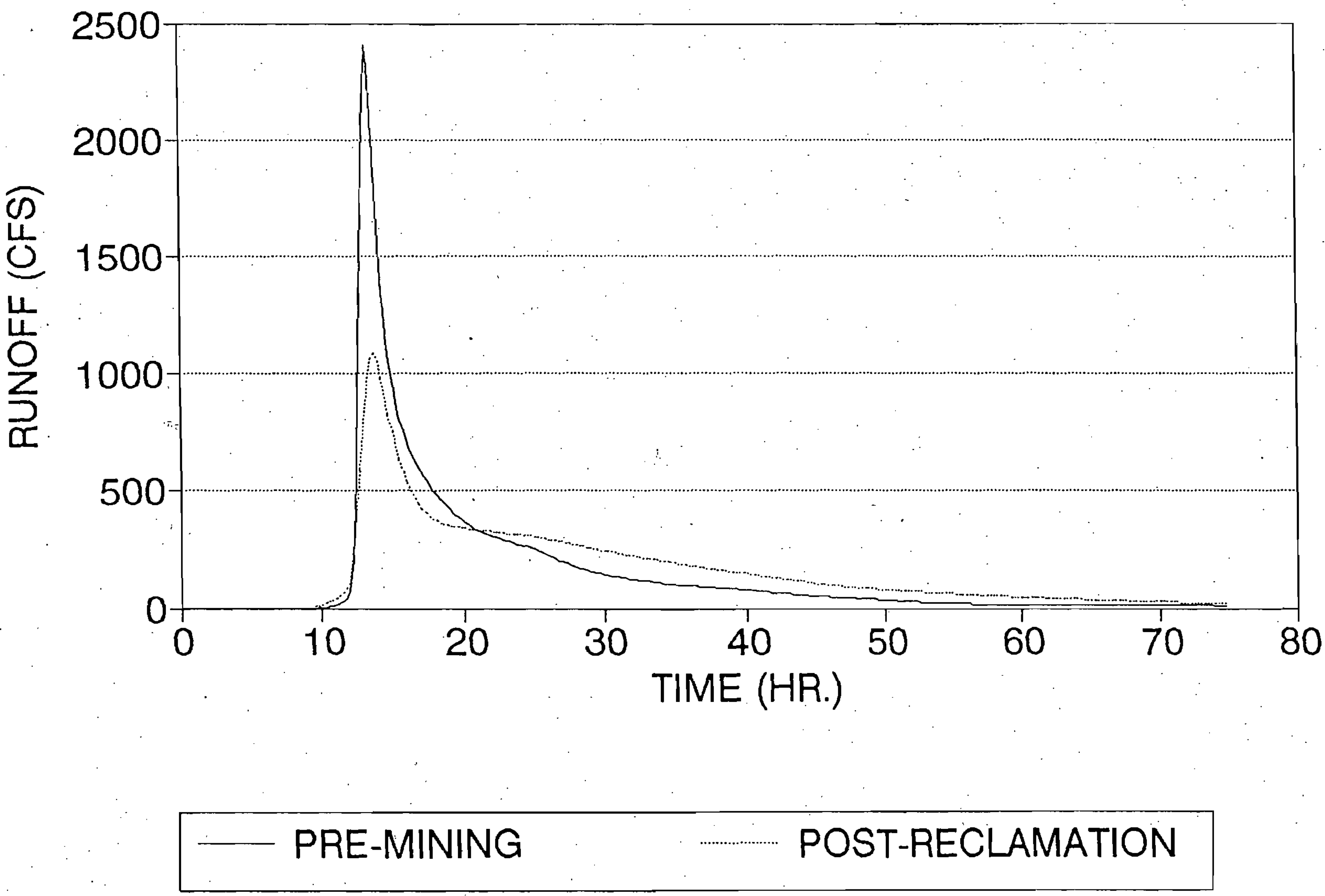



SR/SWFWMD 162 11/92

EXHIBIT WMD-33C

FPC Polk County Site

# CAMP BRANCH
## 25 YEAR STORM EVENT




FPC Polk County Site
EXHIBIT WMD-33D

# CAMP BRANCH

## MEAN ANNUAL STORM EVENT

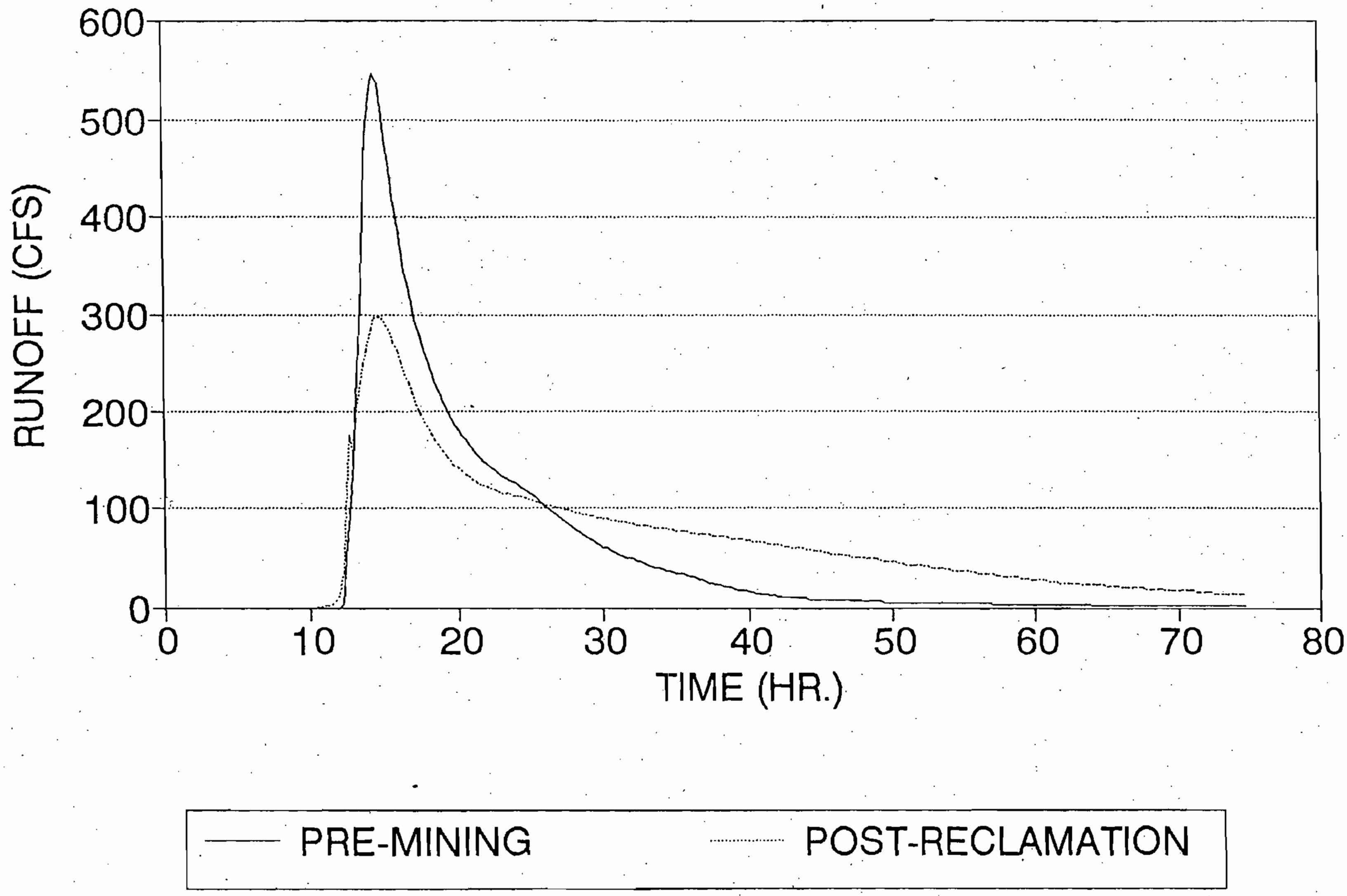









EXHIBIT WMD-33E

FPC Polk County Site

# WELL SUMMARY

Production Wells (See WUP No. 2011944)

| ID | Diam.(in.) | Tot.Depth(ft) | Cased Depth(ft) | Use |
|---|---|---|---|---|
| P-1 | 20 | 880 | 360 | Industrial |
| P-2 | 20 | 880 | 360 | Industrial |
| P-3 | 20 | 880 | 360 | Industrial |
| P-4 | 20 | 880 | 360 | Industrial |
| P-5 | 20 | 880 | 360 | Industrial |
| P-6 | 8 | 500 | 360 | Potable |

Recharge Wells (Proposed wells for ARRP)

| ID | Diam.(in.) | Tot.Depth(ft) | Cased Depth(ft) | Use |
|---|---|---|---|---|
| AR-1 | 24 | 900 | 360 | Recharge |
| AR-2 | 24 | 900 | 360 | Recharge |
| AR-3 | 24 | 900 | 360 | Recharge |
| AR-4 | 24 | 900 | 360 | Recharge |
| AR-5 | 24 | 900 | 360 | Recharge |
| AR-6 | 24 | 900 | 360 | Recharge |

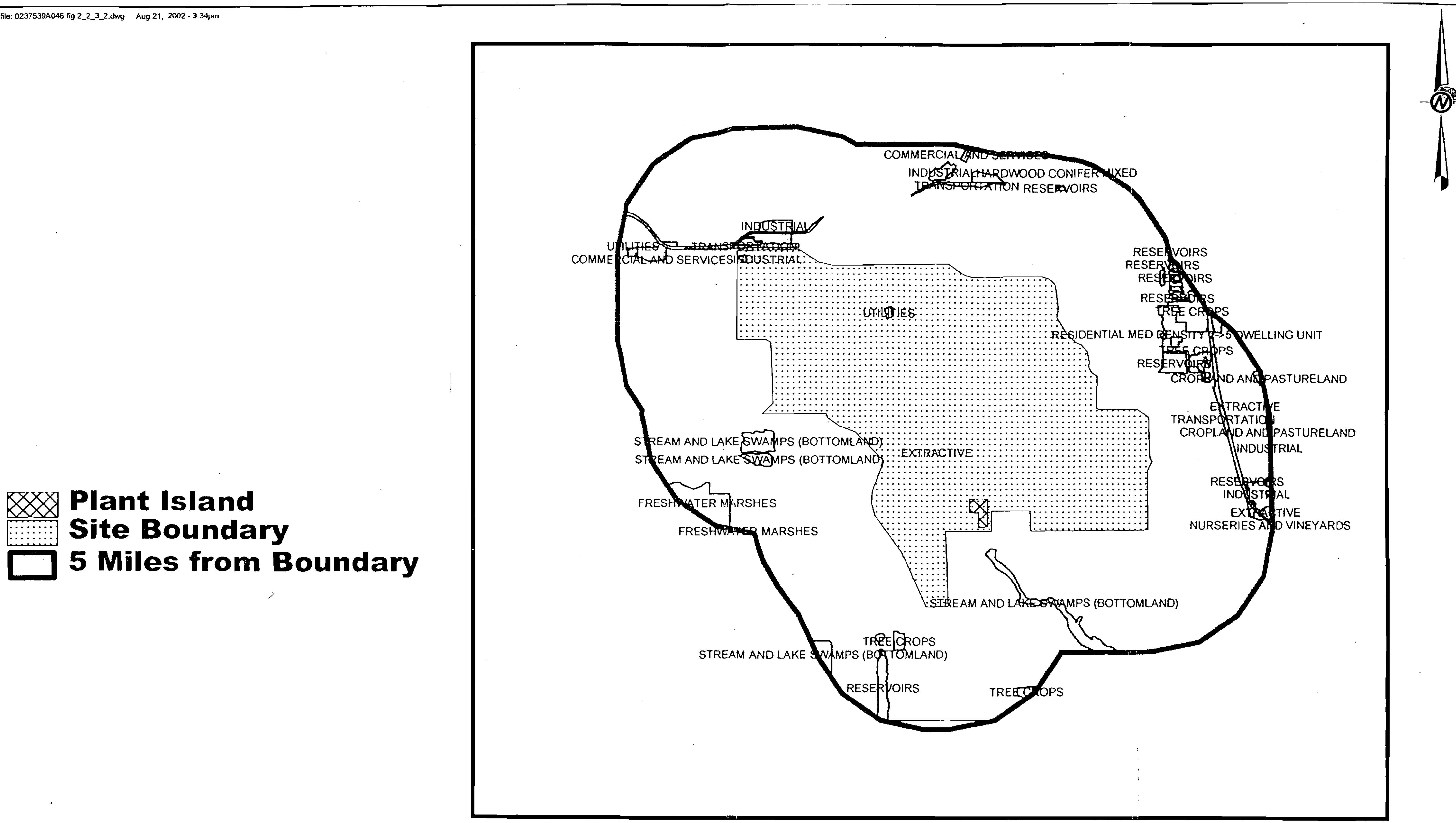
Monitor Wells (Proposed ARRP Monitor)

| ID | Diam.(in.) | Tot.Depth(ft) | Cased Depth(ft) | Use |
|---|---|---|---|---|
| ARM-1 | 8 | 600 | 360 | Monitor |
| ARM-2 | 8 | 600 | 360 | Monitor |
| ARM-3 | 8 | 600 | 360 | Monitor |

New Well Locations

| Owner ID. | Lat. | Long. | Sect. | Twn. | Rng. |
|---|---|---|---|---|---|
| AR-1 | 27 48 39 | 81 52 17 | 1 | 31S | 24E |
| AR-2 | 27 48 39 | 81 52 30 | 1 | 31S | 24E |
| AR-3 | 27 48 39 | 81 52 42 | 2 | 31S | 24E |
| AR-4 | 27 48 39 | 81 52 54 | 2 | 31S | 24E |
| AR-5 | 27 48 39 | 81 53 06 | 2 | 31S | 24E |
| AR-6 | 27 48 39 | 81 53 18 | 2 | 31S | 24E |
| ARM-1 | 27 48 51 | 81 52 16 | 1 | 31S | 24E |
| ARM-2 | 27 48 39 | 81 52 30 | 1 | 31S | 24E |
| ARM-3 | 27 48 21 | 81 52 17 | 1 | 31S | 24E |

Drawing file: 0237539A046 fig 2_2_3_2.dwg Aug 21, 2002 - 3:34pm




SOURCE: SOUTHWEST FLORIDA WATER MANAGEMENT DISTRACT 1999 LAND USE

Florida Power
A Progress Energy Company
Hines Energy Complex

FIGURE 2.2.3-2
EXISTING LAND USE WITHIN
5 MILES OF THE PLANT

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Bruce Baldwin
Vice President, Combustion Turbine Operations
Florida Power
P. O. Box 14042, MAC BB1A
St. Petersburg, FL 33733-4042

***COMPLETE THIS SECTION ON DELIVERY***

A. Signature
X D. Clark
☐ Agent
☐ Addressee

B. Received by ( *Printed Name*) D Clark

C. Date of Delivery

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

ST. PETERSBURG, FL 33733
MAR 0 7 2003
CALLER SERVICE

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

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

7001 0320 0001 3692 6846

PS Form 3811, August 2001 Domestic Return Receipt 102595-02-M-1540

7001 0320 0001 3692 6846

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

OFFICIAL USE

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

Postmark Here

*Sent To* Bruce Baldwin
*Street, Apt. No.; or PO Box No.* PO Box 14042, MAC BB1A
*City, State, ZIP+4* St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. Roger Zirkle
Plant Manager - Hines Energy Complex
Progress Energy Florida
Post OFfice Box 14042-MAC-BB1A
St. Petersburg, FL 33733-4042

2. 7001 0320 0001 3692 6075

***COMPLETE THIS SECTION ON DELIVERY***

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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

ST. PETERSBURG, FL 33733
SEP 22 2003

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

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

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

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

OFFICIAL USE

7001 0320 0001 3692 6075

| | | |
|---|---|---|
| Postage | $ | Postmark Here |
| Certified Fee | | |
| Return Receipt Fee (Endorsement Required) | | |
| Restricted Delivery Fee (Endorsement Required) | | |
| **Total Postage & Fees** | $ | |

*Sent To* Roger Zirkle

*Street, Apt. No.; or PO Box No.* PO Box 14042, MAC -BB1A

*City, State, ZIP+4* St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

**SENDER: *COMPLETE THIS SECTION***

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

1. Article Addressed to:

Mr. John J. Hunter
Project Technical Specialist
Progress Energy Florida, Inc.
Post Office Box 14042, MAC-BB1A
St. Petersburg, FL 33733-4042

**COMPLETE THIS SECTION ON DELIVERY**

A. Received by *(Please Print Clearly)*

B. Date of Delivery

C. Signature

X

☐ Agent
☐ Addressee

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

ST. PETE CALLER SERVICE
SEP 22 2003

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

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

2. 7001 0320 0001 3692 6082

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

7001 0320 0001 3692 6082

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

**OFFICIAL USE**

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

Postmark Here

*Sent To* John J. Hunter
*Street, Apt. No.; or PO Box No.* PO Box 14042, MAC-BB1A
*City, State, ZIP+4* St. Petersburg, FL 33733-4042

PS Form 3800, January 2001 See Reverse for Instructions

Florida Power
A Progress Energy Company

RECEIVED
MAR 28 2003
BUREAU OF AIR REGULATION

March 27, 2003

Mr. Al Linero, P.E., Administrator
New Source Review Section
Division of Air Resources Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399-2400

Dear Mr. Linero:

Re: Hines Energy Complex – Power Block 3
Project No. 1050234-006-AC
Draft Permit No. PSD-FL-330
Public Notice – Proof of Publication

Please find enclosed the "proof of publication" for the public notice of the above referenced draft permit. The notice was published in the Lakeland Ledger on March 21, 2003.

Please contact me if you have any questions or need additional information.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services

jjh/JJH059

Enclosure

c(w/enc): Greg DeAngelo, FDEP - Tallahassee
G. Kettle, EPA
J. Bunyak, NPS

# AFFIDAVIT OF PUBLICATION
## THE LEDGER
## Lakeland, Polk County, Florida

RECEIVED
MAR 28 2003
BUREAU OF AIR REGULATION

**Case No ....................** | **Attach Notice Here**

**STATE OF FLORIDA)**
**COUNTY OF POLK)**

Before the undersigned authority personally appeared Sandra Heath, who on oath says that she is Assistant Classified Advertising Manager of The Ledger, a daily newspaper published at Lakeland in Polk County, Florida; that the attached copy of advertisement, being a

......................Notice Of Intent..........................................

.............................................................................

in the matter of......Permit No. PSD-FL-330.................................

.............................................................................

.............................................................................

in the....................................................................

.............................................................................

Court, was published in said newspaper in the issues of.......................

..............................3-21; 2003........................................

.............................................................................

Affiant further says that said The Ledger is a newspaper published at Lakeland, in said Polk County, Florida, and that the said newspaper has heretofore been continuously published in said Polk County, Florida, daily, and has been entered as second class matter at the post office in Lakeland, in said Polk County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the purpose of securing this advertisement for publication in the said newspaper.

Signed Sandra Heath

Sandra Heath
Assistant Classified Advertising Manager
Who is personally known to me.

Sworn to and subscribed before me this 21st ..........................

day of March ......... A.D. 20 03 .........

Patricia Ann Rouse
Notary Public
PATRICIA ANN ROUSE

PATRICIA ANN ROUSE
MY COMMISSION # CC 976018
EXPIRES: October 17, 2004
Bonded Thru Notary Public Underwriters

(Seal)

My Commission Expires.........................................

LL111248 H713 Progress Energy

**PUBLIC NOTICE OF INTENT TO ISSUE PSD PERMIT**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Draft permit No. PSD-FL-330

Florida Power Hines Energy Complex, New Combined Cycle Power Block 3
Polk 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 Florida Power. The permit is one of several authorizations needed to construct a nominal 530 megawatt (MW) combined cycle gas project at the Florida Power Hines Energy Complex, which is located approximately 7 miles south-southwest of Bartow and 5 miles west-northwest of Fort Meade, Polk County, Florida. In accordance with Rule 62-212.400, Florida Administrative Code (F.A.C.), Best Available Control Technology (BACT) determinations were required for emissions of carbon monoxide (CO), nitrogen oxides (NOx), particulate matter ($PM/PM_{10}$), sulfur dioxide ($SO_2$), sulfuric acid mist (SAM), and volatile organic compounds (VOC). The applicant's authorized representative is Mr. Bruce Baldwin; Vice President - Combustion Turbine Operations. The applicant's address is Florida Power, P.O. Box 140442 - MAC BB1A, St. Petersburg, FL 33733-4042.

The applicant proposes to construct a "2-on-1" combined cycle Power Block 3 consisting of the following new equipment: two 170 MW gas turbine-electrical generator sets (CT 3A and CT 3B), two unfired heat recovery steam generators, and a common steam-electrical generator (190 MW). The gas turbines will be fired primarily with natural gas, with up to the equivalent of 720 hours per year per turbine of very low sulfur distillate oil allowed as a restricted alternate fuel. The gas turbines will only be operated in combined cycle mode. Additional equipment includes two 125-foot stacks.

During operation, a selective catalytic reduction (SCR) system with ammonia injection will be used in conjunction with dry low-NOx combustion (gas firing) and wet injection (oil firing) to further reduce NOx emissions. Emissions of CO, $PM/PM_{10}$, SAM, $SO_2$, and VOC will be minimized by the efficient, high-temperature combustion of very low sulfur fuels (natural gas and distillate oil). Emissions of CO and NOx will be continuously monitored to demonstrate compliance with the conditions of the permit. When the turbines are firing natural gas, the permit will limit emissions of CO to 10 parts per million by volume on a dry basis (ppmvd) and emissions of NOx to 2.5 ppmvd, both as corrected to 15 percent oxygen. The Department determines that these control techniques and equipment represent BACT in accordance with Rule 62-212.400, F.A.C. Emissions standards for oil firing, VOC emissions, and ammonia slip are presented in t he draft permit on file with the Department.

Based on the the initial application, the maximum potential annual emissions from the combined cycle gas turbines that comprise new Power Block 3 are summarized in the following table. It is noted that some of the annual emissions estimates will be less because of lower standards specified in the DRAFT permit.

| Pollutant | Maximum Tons Per Year | PSD Significant Emission Rate Tons Per Year | PSD Review Required? |
|---|---|---|---|
| CO | 744 | 100 | Yes |
| Lead (Pb) | 0.02 | 0.6 | No |
| NOx | 267 | 40 | Yes |
| $PM/PM_{10}$ | 121/121 | 15/25 | Yes |
| $SO_2$ | 137 | 40 | Yes |
| SAM | 21 | 7 | Yes |
| VOC | 57 | 40 | Yes |

According to the applicant, maximum predicted air quality impacts due to emissions from the proposed new project are less than the applicable PSD Class II significant impact levels. Therefore, multi-source modeling was not required. The predicted impacts in the Chassahowitzka National Wilderness Area are less than the applicable PSD Class I significant impact levels; therefore, multi-source Class I PSD increment modeling was not required.

Based on the required analysis, the Department has reasonable assurance that the proposed project will not cause or significantly contribute to a violation of any ambient air quality standard or PSD increment. The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

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

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within fourteen 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), F.S., 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, F.A.C.

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

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

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

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

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8318
Telephone: (813)744-6100
Fax: (813)744-6084

The complete project file includes the application, technical evaluations, Draft Permit, and the information submitted by the authorized representative, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Administrator of the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call (850)488-0114 for additional information. The draft permit, technical evaluation and preliminary BACT determination can be accessed at www.dep.state.fl.us/air/permitting/construct.htm.

H713 - 3-21; 2003