Progress Energy

April 20, 2006

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BUREAU OF AIR REGULATION

Mr. Jeff Koerner, PE
Professional Engineer Administrator
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, M.S. 5500
Tallahassee, Florida 32399-2400

RE: Application for Title V Permit Renewal and Title V Permit Revision
Florida Power Corporation dba Progress Energy Florida, Inc.
Hines Energy Complex
Title V Permit No. 1050234-008-AV/-012-AV
Facility ID 1050234
Project No: 1050234-014-AV

Dear Mr. Koerner:

Please find enclosed an application for both the renewal and revision of the Florida Power Corporation dba Progress Energy Florida, Inc. ("PEF") Hines Energy Complex Title V Permit. The Title V Permit revision request is to include the requirements of the Power Block 3, Emission Unit Nos. -016 and -017, air construction permit (1050234-006-AC/-013-AC).

Thank you for your assistance. Please let me know at (727) 820-5962, if you have any questions.

Sincerely,

Ann Quillian, PE
Senior Environmental Specialist
Environmental Services Section

Enclosure

cc: Mr. Jason Waters, FDEP Southwest District

Progress Energy Florida, Inc.
100 Central Avenue
Saint Petersburg, FL 33701

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APR 21 2006
BUREAU OF AIR REGULATION

TITLE V OPERATION PERMIT RENEWAL APPLICATION FOR HINES ENERGY COMPLEX

Prepared for:

Florida Power Corporation dba Progress Energy Florida, Inc.
100 Central Avenue, CX1B
St. Petersburg, FL 33701

Prepared by:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

April 2006
0639512

DISTRIBUTION:
4 Copies – FDEP
2 Copies – Progress Energy Florida, Inc.
1 Copy – Golder Associates Inc.

Department of
Environmental Protection
Division of Air Resource Management
APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit for a proposed project:

- subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- at an existing federally enforceable state air operation permit (FESOP) or Title V permitted facility.

Air Operation Permit – Use this form to apply for:

- an initial federally enforceable state air operation permit (FESOP); or
- an initial/revised/renewal Title V air operation permit.

Air Construction Permit & Revised/Renewal Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Florida Power Corporation dba Progress Energy Florida, Inc.**
2. Site Name: **Hines Energy Complex**
3. Facility Identification Number: **1050234**
4. Facility Location...:
   Street Address or Other Locator: **County Road 555; 2.5 miles South of CR 640**
   City: **Bartow** County: **Polk** Zip Code: **33830**
5. Relocatable Facility? ☐ Yes ☒ No
6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ann Quillian, P.E.**
2. Application Contact Mailing Address...
   Organization/Firm: **Progress Energy Florida, Inc.**
   Street Address: **100 Central Avenue – CX1B**
   City: **St. Petersburg** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers...
   Telephone: **(727) 820-5962** ext. Fax: **(727) 820-5229**
4. Application Contact Email Address: **Ann.Quillian@pgnmail.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Project Number(s):	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

APPLICATION INFORMATION

Purpose of Application

This application for air permit is submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

Air Operation Permit

☐ Initial Title V air operation permit.

☒ Title V air operation permit revision.

☒ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☐ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

The application represents renewal of Title V Permit No. 1050234-012-AV and revision to include Construction Permit No. 1050234-013-AC / PSD-FL-330. Emission Unit No. 004, Emergency Diesel Generator was never installed, therefore request that it be removed from the Title V permit.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
001	CT1A – Power Block 1		NA
002	CT1B – Power Block 1		NA
014	CT2A – Power Block 2		NA
015	CT2B – Power Block 2		NA
016	CT3A – Power Block 3		NA
017	CT3B – Power Block 3		NA
003	Auxiliary Steam Boiler		NA
775047,001	Relocatable Diesel Generators		NA

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :

2. Owner/Authorized Representative Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

4. Owner/Authorized Representative Email Address:

5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the facility addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other requirements identified in this application to which the facility is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit.

   _____ _____
   Signature Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial/revised/renewal Title V permit or concurrent processing of an air construction permit and a revised/renewal Title V permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
   Martin J. Drango, Plant Manager

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):
   - ☒ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.
   - ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively.
   - ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.
   - ☐ The designated representative at an Acid Rain source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: **Florida Power Corporation dba Progress Energy Florida, Inc.**
   Street Address: **100 Central Avenue - HE44**
   City: **St. Petersburg** State: **FL** Zip Code: **33701**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**

5. Application Responsible Official Email Address:

6. Application Responsible Official Certification:
   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

Martin J. Drango — Signature

4/18/06 — Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **5100 West Lemon Street**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. Fax: **(813) 287-1716**
4. Professional Engineer Email Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☒, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☐, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature (seal)

4/19/06
Date

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
** **Board of Professional Engineers Certificate of Authorization #00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **414.4** North (km) **3073.9**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/47/19** Longitude (DD/MM/SS) **81/52/10**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment : **Power Block 1 consists of two combined cycle combustion turbines with heat recovery steam generators (HRSGs), for a nominal total of 500 MWs, a 99 MMBtu/hr auxiliary boiler, and a 97,570 barrel fuel oil storage tank. Power Block 2 consists of two combined cycle combustion turbines with unfired HRSGs, and a single steam-turbine electrical generator. This application is for the Title V renewal of the existing units plus the addition of Power Block 3, a nominal 530 MW combined cycle application. The Emergency Diesel Generator, EU-004, was never installed. It is requested that EU-004 be removed from the Title V permit.**			

Facility Contact

1. Facility Contact Name: **Martin J. Drango, Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **Progress Energy Florida, Inc. - Hines Energy Complex** Street Address: **7700 County Road 555** City: **Bartow** State: **FL** Zip Code: **33830**
3. Facility Contact Telephone Numbers: Telephone: **(863) 519-6103** ext. Fax: **(863) 519-6110**
4. Facility Contact Email Address:

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I. that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official Email Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
Particulate Matter - Total (PM)	**A**	**N**
Sulfur Dioxide (SO_2)	**A**	**N**
Nitrogen Oxides (NO_x)	**A**	**N**
Carbon Monoxide (CO)	**A**	**N**
Volatile Organic Compounds (VOC)	**A**	**N**
Sulfuric Acid Mist (SAM)	**B**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility Wide Cap [Y or N]? (all units)	3. Emissions Unit ID No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **PEF-FI-C1** ☐ Previously Submitted, Date:____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date:____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **PEF-FI-C3** ☐ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:____ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction or Modification: ☐ Attached, Document ID:____
3. Rule Applicability Analysis: ☐ Attached, Document ID:____
4. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification (Rule 62-212.400(2), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
6. Preconstruction Air Quality Monitoring and Analysis (Rule 62-212.400(5)(f), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
7. Ambient Impact Analysis (Rule 62-212.400(5)(d), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(5)(h)5., F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(5)(e)1. and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.):
   ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities (Required for initial/renewal applications only):
   ☒ Attached, Document ID:**PEF-FI-CV1** ☐ Not Applicable (revision application)

2. Identification of Applicable Requirements (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought):
   ☒ Attached, Document ID:**PEF-FI-CV2**
   ☐ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan (Required for all initial/revision/renewal applications):
   ☒ Attached, Document ID:**PEF-FI-CV3**
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI (If applicable, required for initial/renewal applications only):
   ☐ Attached, Document ID:____
   ☐ Equipment/Activities On site but Not Required to be Individually Listed
   ☒ Not Applicable

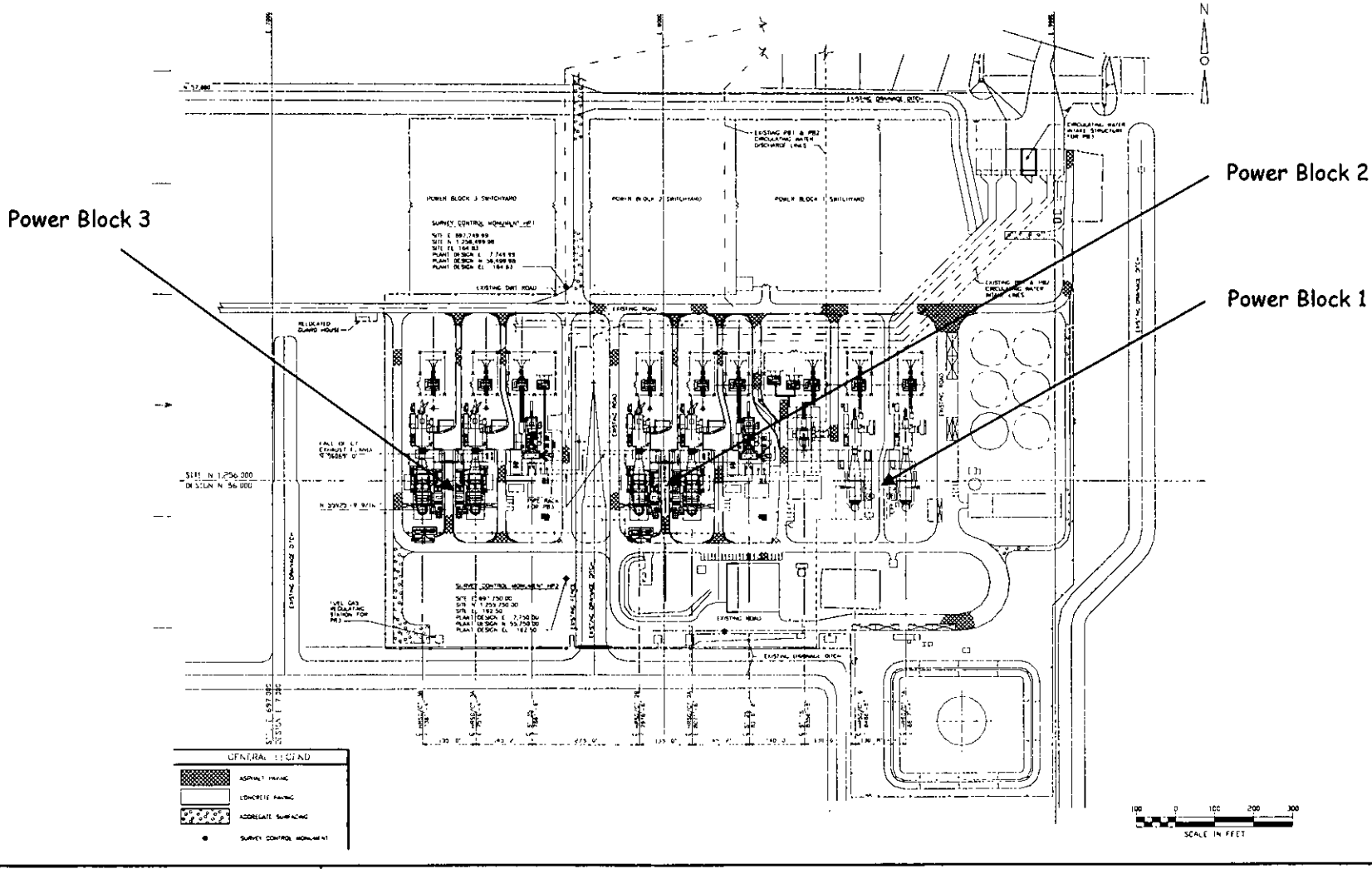
5. Verification of Risk Management Plan Submission to EPA (If applicable, required for initial/renewal applications only) :
   ☐ Attached, Document ID:____ ☒ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID:**PEF-FI-CV6** ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT PEF-FI-C1

FACILITY PLOT PLAN



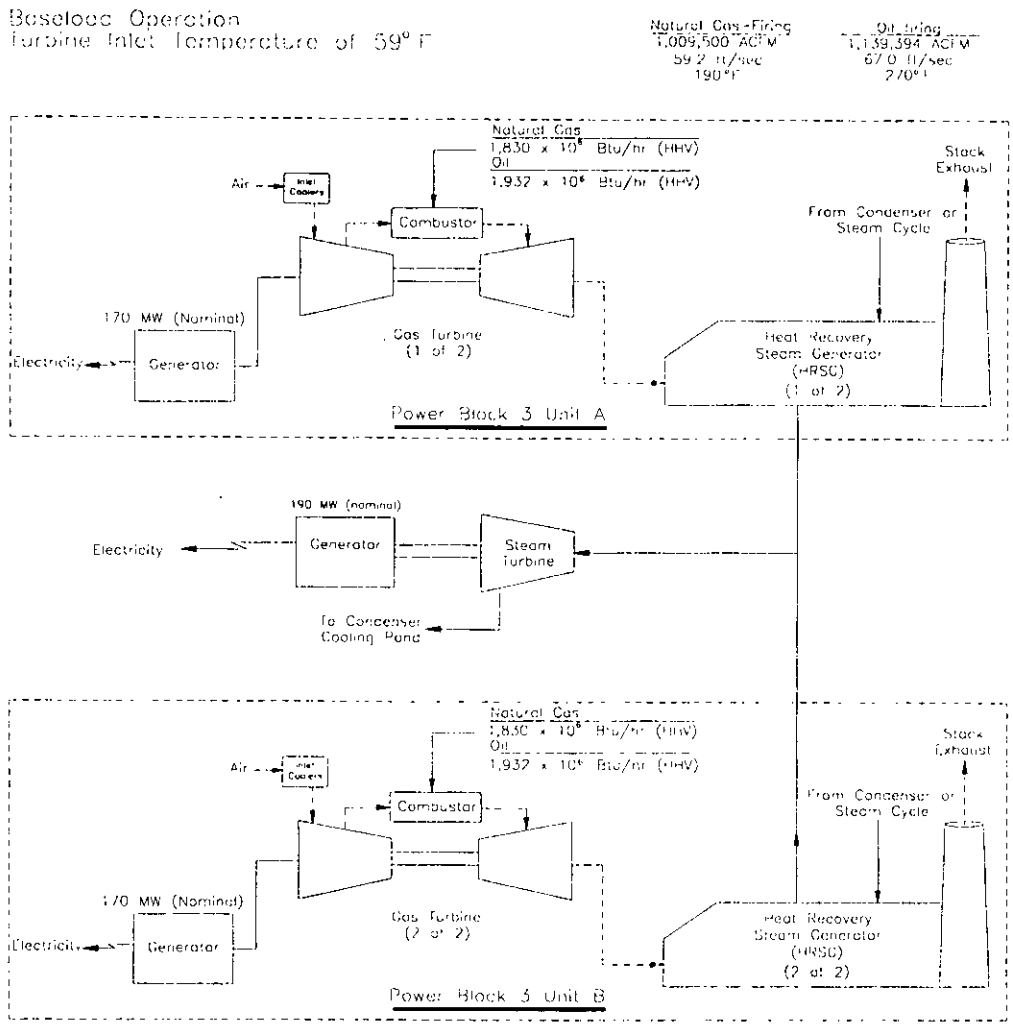
PROGRESS ENERGY CORPORATION

Hines Energy Complex

Facility Plot Plan

ATTACHMENT PEF-FI-C2

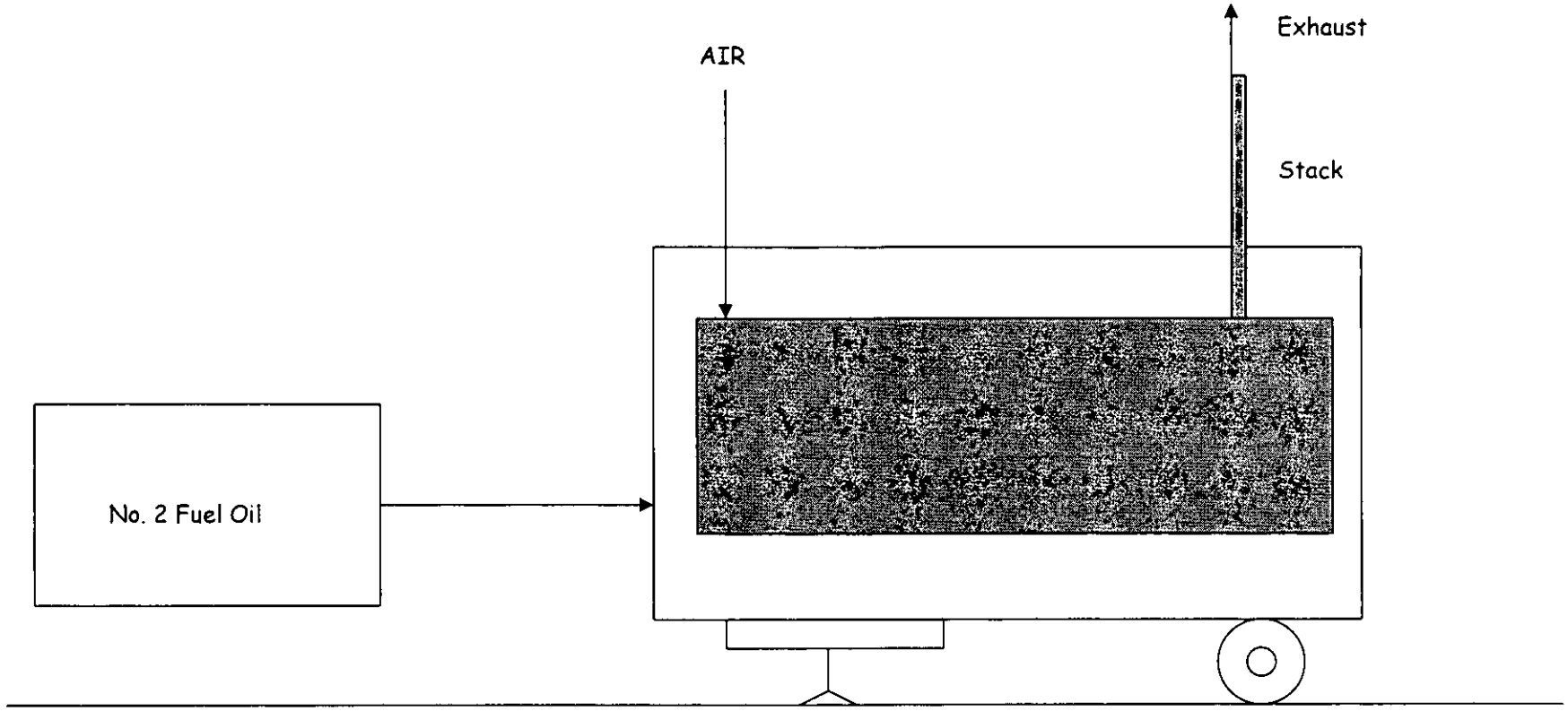
PROCESS FLOW DIAGRAM



PROGRESS ENERGY CORPORATION

Hines Energy Complex

POWER BLOCKS 1 - 3 - PROCESS FLOW DIAGRAM



PROGRESS ENERGY CORPORATION

Hines Energy Complex

RELOCATABLE DIESEL GENERATORS PROCESS FLOW DIAGRAM

ATTACHMENT PEF-FI-CV1

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT PEF-FI-CV1
LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

The following page lists the unregulated and insignificant activities associated with Hines Energy Complex. The insignificant activities identified in this application are provided for information only and are identified as examples of, but not limited to, the insignificant activities identified by the Division of Air Resources Management (DARM). It is understood that such activities do not have to be included with the Title V Application. The insignificant activities identified herein are consistent, in terms of amounts of emissions and types, with those activities listed in DARM's previous guidance.

Pursuant to Rule 62-210.300(3)(b)1. F.A.C., notice is herein provided that the emissions units listed below are not subject to a permit issued by the Department of Environmental Protection and are exempt from permitting until a final determination is made under the Title V permitting requirements (Chapter 62-213 F.A.C.). These units would not have triggered review under Rules 62-212.400 or 62-212.500 or any new source performance standard listed in Rule 62-204.800 F.A.C..

ACTIVITIES

Miscellaneous Buildings H.V.A.C.
C.E.M. Buildings
Laboratory
Maintenance Building
CT Control Room

Sanitary Vents/Stacks
Control Building
Maintenance Building
Laboratory

Miscellaneous Buildings Vent/Exhaust Systems
Lab Building
Maintenance Building

Miscellaneous Maintenance Facilities
Air Compressors
Sandblasting Units
Non-Halogenated Solvent Cleaning Operations
Cleaning, Painting, Welding, Coating Hand Held Tools & Equipment
Products Storage in Sealed Containers
Vacuum Cleaning, Solvent Storage, Office Supplies/Equipment
Miscellaneous Gasoline & Diesel Engine Portable Tools & Equipment

Sumps
Oily Wastewater Separators

Emergency Equipment
CO_2-Based Fire Protection System

Combustion Turbine/Steam Turbine
Battery Backup Systems
Steam vents – blowdown vents
Bearing oil vents
Aqueous ammonia relief valves
Natural gas mercaptan injection

Appendix I-1, List of Insignificant Emissions Units and/or Activities
Progress Energy Corporation **FINAL** Permit No.: 1050234-008-AV
Hines Energy Complex

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Sand blaster, welding, lathes, hand-held tools, etc.
2. Diesel generator.
3. Fire water tank(s).
4. Brazing, soldering, or welding equipment.
5. Fire and safety equipment.
6. Surface coating operations within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly provided:

a. Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and

b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.

ATTACHMENT PEF-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

- **Title V Core List**
- **Title V Permit 1050234-008-AV**
- **Title V Modification Permit No. 1050234-012-AV**
- **Construction Permit PSD-FL-330, Project No. 1050234-006-AC**
- **Construction Permit PSD-FL-330, Project No. 1050234-013-AC**

Title V Core List Effective: 03/01/02

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 06-01-01

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 06-21-01

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 11-30-94
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-09-99
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

Progress Energy Florida
Hines Energy Complex
Facility ID No.: 1050234
Polk County

Title V Air Operation Permit Revision
FINAL Permit No.: 1050234-008-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, FL 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Title V Air Operation Permit Revision
FINAL Permit No.: 1050234-008-AV

Table of Contents

Permittee:
Progress Energy Florida
100 Central Avenue, BB1A-HE4
St. Petersburg, Florida 33701-5511

FINAL Permit No.: 1050234-008-AV
Facility ID No.: 1050234
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

This revision is for the incorporation of Power Block 2 at the existing Hines Energy Complex. This facility is located at 7700 County Road 555; 2.5 miles South of County Road 640, Bartow, Polk County; UTM Coordinates: Zone 17, 414.4 km East and 3073.9 km North; Latitude: 27° 47' 19" North and Longitude: 81° 52' 10" West.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix G-1, Heat Input Curve
Appendix T-1, Table of NO_x (lb/hr) vs. Inlet Temperature
Appendix D-1, Description of Start-up Sequence for a Two-on-One Configuration
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-4, Title V Conditions version dated 02/12/02
Appendix SS-1, Stack Sampling Facilities version dated 10/07/96
Table 297.310-1, Calibration Schedule version dated 10/07/96
Figure 1 - Summary Report-Gaseous And Opacity Excess
Emission And Monitoring System Performance Report version dated 10/07/96
Alternate Sampling Procedure: ASP Number 97-B-01
Phase II Acid Rain Application/Compliance Plan dated 07/03/98

Effective Date: January 1, 2002
Revision Effective Date: November 1, 2004
Renewal Application Due Date: July 5, 2006
Expiration Date: December 31, 2006

Michael G. Cooke, Director
Division of Air Resource Management

MGC/tv/mph

Section I. Facility Information.

Subsection A. Facility Description.

Power Block 1 consists of two combined cycle combustion turbines with heat recovery steam generators (HRSGs), for a nominal total of 500 MWs, a 99 MMBtu/hr auxiliary boiler, a 1,300 kW diesel generator and a 97,570 barrel fuel oil storage tank. Emissions from each CT and HRSG combination are vented through a single stack for each.

Power Block 2 consists of two combined cycle combustion turbines with unfired heat recovery steam generators (HRSGs), and a single steam-turbine electrical generator. The entire facility (inclusive of both Power Blocks) has a total generating capacity of 1030 MW.

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V permit application received January 19, 1999, and the Title V application for permit revision received February 16, 2004 this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	Brief Description
-001	170 MW Westinghouse 501F Combustion Turbine Unit 1
-002	170 MW Westinghouse 501F Combustion Turbine Unit 2
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B
-003	Auxiliary Steam Boiler
-004	Emergency generator
7775047, 001	Relocatable diesel generator(s) with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generator(s) are uncontrolled.

Unregulated Emissions Units and/or Activities
{See Appendix U-1}

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
Table 1-1, Air Pollutant Emission Allowables and Terms
Table 2-1, Compliance Testing Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History/ID Number Changes

Documents on file with USEPA
Risk Management Plan submitted to the RMP Reporting Center on June 21, 2004.

These documents are on file with the permitting authority:
Initial Title V Permit Application received January 19, 1999.
Additional Information Requested dated March 9, 1999.
FPC response dated August 27, 1999.
FPC response dated November 9, 1999.
Comments from Florida Power Corporation received on February 10, 2000.
DEP letter to USEPA dated March 23, 2000.
USEPA Region 4 letter to Alabama DEM received by fax on May 26, 2000.
Construction Permit No. PSD-FL-195B, issued August 16, 2000.
Title V Permit Revision Application received October 26, 2000.
Title V Permit Revision Application received February 16, 2004.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard. Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. As required by Section 112(r)(7)(B)(iii) of the CAA and 40 CFR 68, the owner or operator shall submit an updated Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center.
b. As required under Section 252.941(1)(c), F.S., the owner or operator shall report to the appropriate representative of the Department of Community Affairs (DCA), as established by department rule, within one working day of discovery of an accidental release of a regulated substance from the stationary source, if the owner or operator is required to report the release to the United States Environmental Protection Agency under Section 112(r)(6) of the CAA.
c. The owner or operator shall submit the required annual registration fee to the DCA on or before April 1, in accordance with Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.

Any required written reports, notifications, certifications, and data required to be sent to the DCA, should be sent to:

Department of Community Affairs
Division of Emergency Management
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100
Telephone: 850/413-9921, Fax: 850/488-1739

Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
P.O. Box 1515
Lanham-Seabrook, Maryland 20703-1515
Telephone: 301/429-5018

Any required reports to be sent to the National Response Center, should be sent to:

National Response Center
EPA Office of Solid Waste and Emergency Response
USEPA (5305 W)
401 M Street, SW
Washington, D.C. 20460
Telephone: 1/800/424-8802

Send the required annual registration fee using approved forms made payable to:
Cashier
Department of Community Affairs
State Emergency Response Commission
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2149
[Part IV, Chapter 252, F.S. and Rule 9G-21, F.A.C.]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. Not federally enforceable. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to 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)(a), F.A.C.; and, proposed by applicant in the initial Title V permit application received January 19, 1999.]

8. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include:

- Maintenance of paved areas as needed,
- Regular mowing of grass and care of vegetation, and
- Limiting access to plant property by unnecessary vehicles.

[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in the initial Title V permit application received January 19, 1999.]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year.
{See condition 51., APPENDIX TV-4, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southwest District or office.

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100, Fax: 813/744-6084

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155, Fax: 404/562-9164

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-001	170 MW Westinghouse 501F Combustion Turbine
-002	170 MW Westinghouse 501F Combustion Turbine

Emission units 001 and 002 each consist of a combined cycle Westinghouse 501F Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 1,915 mmBtu/hr (LHV) while firing natural gas and 2,020 MMBtu/hr (LHV) while firing fuel oil. NO_x emissions are controlled with dry low NO_x burners (DLN) and/or Selective Catalytic Reduction (SCR) for natural gas firing and wet injection for fuel oil firing. Each combustion turbine incorporates an unfired heat recovery steam generator.

{Permitting notes: This emissions unit is regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-195B; Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. At an ambient temperature of 59 °F, each combustion turbine shall not exceed 1,915 MMBtu/hr (LHV) while firing natural gas, or 2,020 MMBtu/hr (LHV) while firing fuel oil. See Attachment **G-1** for a plot of heat input versus temperature.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and PSD-FL-195B]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **H.4.**

A.3. Methods of Operation - (i.e., Fuels). Only natural gas, having a maximum sulfur content of 1 grain per 100 cf of natural gas, or low sulfur fuel oil having a maximum sulfur content of 0.05%, by weight, shall be fired in each combustion turbine at all times. The maximum allowable fuel oil consumption for the two turbines is 13,762,806 gallons per year, which is equivalent to an aggregate of 1,000 hours per year of operation at full load.
[Rule 62-213.410, F.A.C.]

A.4. Hours of Operation. Each of the combustion turbines in Power Block 1 may operate continuously, i.e., 8,760 hours/year.

[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Air Pollutant Emission Allowables and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.5. Emissions from the CT, while firing natural gas or low sulfur fuel oil, shall not exceed the following (at 59 °F reference temperature for NO_x emissions) (except during periods of startup, shutdown, malfunction):

		CT Allowables		
Pollutant	**Fuel**	**Basis(g)**	**lbs/hr.**	**TPY(b)**
NO_x (a)	Gas	12 ppmvd (h)	73(i)	639
	Oil	42 ppmvd (c)(h)	305	153
VOC (d)	Gas	7 ppmvw	10.4	91
	Oil	10 ppmvw	19.0	5.6
SO_2	Gas(f)		4.7	44
	Oil(f)		94	47
CO	Gas	25 ppmvd	77	675
	Oil	30 ppmvd	93	47
VE	Gas	10 percent opacity		
	Oil	20 percent opacity		
PM/PM_{10}	Gas		15.6	79
	Oil(e)		44.8	21

a. Pollutant emission rates may vary depending on ambient conditions (compressor inlet temperatures)and the CT characteristics. Manufacturer's curves for the NO_x emission rate correction to other temperatures at different loads were provided to the DEP for review and are now a part of this permit (Appendix G-1). The manufacturer's curves shall be used to establish pollutant emission rates over a range of temperatures for the purpose of compliance determination. Emission limitations in LB/HR/CT of NO_x are blocked 24-hour averages (midnight to midnight) and are calculated as follows:

NO_x emissions shall be determined continuously by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 shall be used. Compliance with the NO_x emissions standards in the above table shall be demonstrated with this CEMS system based on a 24-hour block average. Based on CEMS data at the end of each operating day, new 24-hour average emission rates, both actual and allowable (based on compressor inlet temperatures) are calculated from the arithmetic average of all valid hourly emission rates during the previous 24 operating hours. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the NO_x standard. These excess emission periods shall be reported as required in 40 CFR 60.7(b). A valid hourly emission rate shall be calculated for each hour in which

two NO_x and carbon dioxide (or oxygen) concentrations are obtained at least 15 minutes apart. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 24-hour block average.

b. Annual emission limits (TPY) for natural gas are based on a total of two CTs operating at full load 8,760 hours per year (i.e., NO_X - 73 lbs/hr X 2 CTs X 8,760 hrs/yr X 1 ton/2,000 lbs = 639 TPY). Annual emission limits (TPY) for fuel oil are based on full load operation for a total of 1,000 hours per year for the two CTs (i.e., NO_X - 305 lbs/hr X 1,000 hrs/yr X 1 ton/2,000 lbs = 153 TPY).

c. Fuel oil NO_X emissions are based on full load operation and 15 percent oxygen. For fuel oil firing, NO_X levels of 42 ppmvd @ 15 percent O_2 are based on a fuel bound nitrogen content of 0.015 percent or less. The emission limit for NO_X is adjusted as follows for higher fuel nitrogen contents up to a maximum of 0.030 percent by weight:

FUEL BOUND NITROGEN (% BY WEIGHT)	NO_X LEVELS (PPMVD @ 15%O_2)	NO_X EMISSIONS LB/HR/CT	TPY
0.015 or less	42	305	153
0.020	44	320	160
0.025	46	334	167
0.030	48	349	175

See Specific condition **A.6.**

NO_x emissions limits are preliminary for the fuel oil specified in Specific Condition No. **A.3**. FPC shall maintain fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation. Adjustments of the NO_x standard (up and down) shall be calculated and recorded based on a volume weighted average of the nitrogen content of each bulk fuel oil shipment and the nitrogen content of the existing fuel in the storage tank. The NO_x emission allowance (F) for fuel oil shall not be adjusted between fuel oil shipments. Records for these adjusted standards shall be kept on site for a minimum of 5 years.

d. Exclusive of background concentrations.

e. PM/PM_{10} emission limitations include sulfuric acid mist.

f. SO_2 emissions are based on a maximum of 1 grain of S/100 cf of natural gas and 0.05 percent sulfur in the fuel oil.

g. The values are the computational basis for the lb/hr numbers, which are the actual emission limitations.

h. At 15 percent O_2, not ISO corrected.

i. Control of nitrogen oxides from each CT while firing natural gas shall be accomplished using dry low NO_x burners (DLN) and SCR. Ammonia slip shall not exceed 10 ppm.

2. The following CT emissions, determined by BACT, are tabulated for PSD purposes:

ESTIMATED EMISSIONS

POLLUTANT	METHOD OF CONTROL	Basis(b)
Benzene	Natural Gas	BACT
Inorganic Arsenic	No. 2 Fuel Oil (a)	BACT
Beryllium	No. 2 Fuel Oil (a)	BACT
Mercury	No. 2 Fuel Oil (a)	(c)
Pb	No. 2 Fuel Oil (a)	(c)

a. The No. 2 fuel oil shall have a maximum sulfur content of 0.05 percent.

b. Since these pollutants are inherent constituents in the fuel, the basis for control will be by specifying that only natural gas and No. 2 fuel oil can be fired at the facility.

c. Below PSD significant emission levels.

[PSD-FL-195B]

A.6. Oxides of Nitrogen. In addition to the specific NO_x emission limits specified for each turbine, NO_x emissions shall not exceed any of the following limits:

a. Nitrogen oxide emissions, expressed as NO_x shall not exceed:

$$STD = 0.0042 + F$$

where:

STD = allowable NO_x emissions (percent by volume at 15 percent O_2 and on a dry basis).

F = NO_x emission allowance for fuel-bound nitrogen defined by the following table:

Fuel-Bound Nitrogen (% by weight)	F (NO_x % by volume)
$0 < N < 0.015$	0
$0.015 < N < 0.03$	0.04(N-0.015)

where: N = the nitrogen content of the fuel (% by weight).

[PSD-FL-195B]

Excess Emissions

A.7. Excess emissions resulting from startup, shutdown, malfunction, or load change shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period except in the event that the steam turbine has been shut down for 8 hours or more. During a cold start-up to combined cycle operation, up to four hours of excess emissions are allowed in a 24-hour period. Cold start-up is defined as a start-up to combined cycle operation following a steam turbine shutdown of greater than 48 hours. During a warm start up to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine of greater than 8 hours and less than 48 hours.

[Applicant Request, Vendor Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

Monitoring of Operations

A.8. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

A.9. For each combined cycle unit, the permittee shall install, operate, and maintain a continuous emission monitoring system (CEMS) (in accordance with 40 CFR 60, Appendix F or 40 CFR 75, whichever is more stringent) or use other DEP approved alternate methods to monitor nitrogen oxides and, if necessary, a diluent gas (CO_2 or O_2). The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective for the CTs.

1. Each CEMS shall meet performance specifications of 40 CFR 60, Appendix B or 40 CFR 75, whichever is more stringent.

2. CEMS data shall be recorded and reported in accordance with Chapter 40 CFR 60 Appendix A and Subpart GG or 40 CFR 75, whichever is more stringent. The record shall include periods of start up, shutdown, and malfunction. Compliance with condition **A.5.** for NO_X shall be determined by CEMS on a mass emission rate basis (LB/HR) using EPA Method 19 and hourly averaged heat inputs (MMBtu/hr).

3. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

4. The procedures under 40 CFR 60.13 or 40 CFR 75, whichever is more stringent, shall be followed for installation, evaluation, and operation of all CEMS.

5. For purposes of the reports required under this permit, excess emissions are defined as any calculated average emission rate, as determined pursuant to condition **A.7.** herein, which exceeds the applicable emission limits in condition **A.5.**

[PSD-FL-195B]

A.10. Tests Required

a. PM, VE, and CO. Except as provided in specific conditions **A.17.** , **A.18.** and **H.3.** of this permit, emission testing for particulate matter emissions, visible emissions, and carbon monoxide emissions shall be performed annually.

b. Volatile Organic Compounds. The initial test requirement for VOC's was satisfied. [Rules 62-4.070(3), 62-213.440, and 62-297.310(7), F.A.C.]

A.11. The permittee shall monitor sulfur content and nitrogen content of the new No. 2 distillate fuel oil and sulfur content of natural gas. These values may be provided by the vendor and the frequency of determinations of these values shall be as follows:

a. New No. 2 Distillate Fuel Oil. The values, sulfur and nitrogen content, shall be determined on each occasion that fuel is transferred to the storage tanks from any other source. Records of these values shall be kept by the facility for a five year period for regulatory agency inspection purposes.

b. Natural Gas. Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule for the determination of these values shall be followed for the natural gas fired at this facility and shall be as follows:

Custom Fuel Monitoring Schedule for Natural Gas (NG)

1. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the gas turbines.
2. Sulfur Monitoring:
   (a). Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2), or the latest edition(s).
   (b). This custom fuel monitoring schedule shall become effective on the date this permit becomes valid. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333 and the conditions of this permit, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of 2(c).
   (c). If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333 and the conditions of this permit, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.
   (d). Should any sulfur analysis as required in items 2(b) or 2(c) above indicate non-compliance with 40 CFR 60.333 and the conditions of this permit, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.
3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in natural gas quality (i.e., sulfur content varying by more than 10 grains/1000 of gas) shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.
[40 CFR 60.334(b); PSD-FL-195B; and, Custom Fuel Monitoring Schedule Approved on June 1, 2000.]

Test Methods and Procedures

{Permitting note: Table 2-1, Compliance Testing Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A. 12. Critical Fuel Parameters. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of 40 CFR 60.334 testing for sulfur content of the fuel oil in the storage tanks on each occasion that fuel is transferred to the storage tanks from any other source. Testing for fuel bound nitrogen content by ASTM D3431 or D4629 or other equivalent ASTM method, and for fuel oil higher heating value, shall also be conducted on the same schedule.
[40 CFR 60.334(b)]

A.13. Particulate Matter. The test methods for particulate emissions shall be either EPA Method 5 or Method 17 incorporated by reference in Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C. and PSD-FL-195B]

A.14. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rule 62-297.401, F.A.C. and PSD-FL-195B]

A.15. Sulfur Dioxide. The permittee shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows:
ASTM D 4294 (or equivalent) for sulfur content of distillate oil, and;
ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 (or equivalent) for sulfur content of natural gas.
[Rules 62-297.440, and 62-297.620(2)(d), F.A.C.; and PSD-FL-195B]

A.16. a. Carbon Monoxide. The test method for carbon monoxide shall be EPA Method 10.

b. Volatile Organic Compounds. The test method for VOC's shall be EPA Method 18 or Method 25A.
[PSD-FL-195B]

A.17. Frequency of Compliance Tests. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operating permit.
[Rule 62-297.310(7), F.A.C.]

A.18. Annual emissions compliance testing for particulate matter emissions, carbon monoxide emissions, and visible emissions shall be performed for oil and only if fuel oil is more than 400 hours for the emission unit in the previous federal fiscal year.

[PSD-FL-195B]

A.19. Other DEP approved methods may be used for compliance testing after prior Departmental approval.
[PSD-FL-195B]

A.20. To meet the requirements of 40 CFR 60.334(b), the permittee shall use the methods specified in 40 CFR 60.335(a) and (d) to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency.
[40 CFR 60.335(e)]

Continuous Monitoring Requirements

A.21. Oxides of Nitrogen. NO_x emissions shall be determined continuously by a Continuous Emissions Monitoring System (CEMS). A CEMS operated and maintained in accordance with 40 CFR 75 shall be used. Compliance with the NO_x emissions standards in the above table shall be demonstrated with this CEMS system based on a 24-hour block average. Based on CEMS data at the end of each operating day, new 24-hour average emission rates, both actual and allowable (based on compressor inlet temperatures) are calculated from the arithmetic average of all valid hourly emission rates during the previous 24 operating hours. Valid hourly emission rates shall not include periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 where emissions exceed the NO_x standard. These excess emission periods shall be reported as required by 40 CFR 60.7(b). A valid hourly emission rate shall be calculated for each hour in which two NO_x and carbon dioxide (or oxygen) concentrations are obtained at least 15 minutes apart. When monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 24-hour block average.
[PSD-FL-195B]

Recordkeeping and Reporting Requirements

A.22. To determine compliance with the natural gas and fuel oil firing heat input limitation, the permittee shall maintain daily records of natural gas and fuel oil consumption for each turbine, as well as recent records of the heating value for each fuel. All records shall be maintained for a minimum of five years after the date of each record and shall be made available to representatives of the Department upon request.
[Rule 62-4.070(3), F.A.C., and PSD-FL-195B]

Miscellaneous Conditions

A.23. The permittee shall have the option of installing duct module(s) suitable for possible future installation of an oxidation catalyst and/or SCR equipment on each combined cycle generating unit. In the event that the module(s) are not installed in the Heat Recovery Steam Generator (HRSG), the retrofit costs associated with not making provisions for such technology (initially) shall not be considered in any future economic evaluation to justify not installing SCR or an oxidation catalyst.
[PSD-FL-195B]

A.24. Units to be constructed or modified in later phases of the project will be reviewed under the supplementary review process of the Power Plant Siting Act. If site construction has not commenced within 18 months of issuance of this certification, then FPC shall obtain from DEP a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced.
[PSD-FL-195B]

Common Conditions

A.25. These emissions unit are also subject to conditions **H.1.** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-003	Auxiliary Steam Boiler

Emission unit 003 is a Steam boiler rated at 99 MMBtu at 1,050 Btu/cf natural gas (HHV). The boiler provides steam for periods of Combustion Turbine startup or quick startup out of a short-term shutdown. The boiler has no add-on pollution control equipment. Air pollution emissions are controlled by efficient combustion and firing natural gas.

{Permitting note: The emissions unit is regulated under NSPS - 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate for the boiler is as follows:

Unit No.	Fuel Type	MMBtu/hr Heat Input
003	Natural Gas	99

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and PSD-FL-195B]

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **H.4.**

B.3. Methods of Operation - (i.e., Fuels). Only natural gas shall be fired in the auxiliary steam boiler at all times.
[Rule 62-213.410, F.A.C.]

B.4. Hours of Operation. The operation of the auxiliary steam boiler shall be limited to a maximum of 1000 hours per year and only during periods of cold CT startup or quick startup out of a short term shutdown mode, when no other source of steam is available or during periodic testing.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Air Pollutant Emission Allowables and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.5. Nitrogen Oxides. NO_x emissions shall not exceed 0.1 lb/MMBtu for natural gas firing based on vendor-certified stack test data for this model of auxiliary boiler.
[PSD-FL-195B]

B.6. Sulfur dioxide. Emissions shall be limited by firing natural gas.
[Rule 62-296.406(2), F.A.C., PSD-FL-195B]

B.7. Visible emissions. Visible emissions shall not exceed 10 percent opacity while burning natural gas.
[PSD-FL-195B]

Excess Emissions

B.8. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and 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 a longer duration.

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

B.9. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62.210.700(2), F.A.C.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.10. Visible emissions. The test method for visible emissions shall be EPA Method 9, incorporated in Chapter 62-297, F.A.C.
[Rules 62-213.440 and 62-297.401, F.A.C.]

B.11. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
    a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
    b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the

selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value. [Rule 62-297.401, F.A.C.]

B.12. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or

b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or

c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.]

B.13. All recorded data shall be maintained on file by the Source for a period of five years. [Rule 62-213.440, F.A.C.]

B.14. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department Southwest District office or the Southwest District Branch office on the results of each such test.

(b) The required test report shall be filed with the Department Southwest District office or the Southwest District Branch office as soon as practical but no later than 45 days after the last sampling run of each test is completed.

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

B.15. This emissions unit is also subject to conditions **H.1** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection C. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-004	Emergency Diesel Generator rated at 1,300 kW to be used for site emergency power and periodic testing.

{Permitting note: The emissions unit is regulated under Rule 62-296.406, F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum heat input rate shall not exceed 13 million Btu per hour.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

C.2. Methods of Operation - (i.e., Fuels). Only low sulfur fuel oil with a maximum sulfur content of 0.05%, by weight, shall be fired in the diesel generator.
[Rule 62-213.410, F.A.C.; and PSD-FL-195B]

C3. Hours of Operation. The hours of operation for this emissions unit shall not exceed 100 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Air Pollutant Emission Allowables and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.4. Visible emissions. Visible emissions from the generator shall not exceed 20 percent opacity.
[Rule 62-296.320(4)(b)(1)., F.A.C.; and, PSD-FL-195B]

C.5. Sulfur Dioxide. Sulfur dioxide shall be limited by firing only low sulfur fuel oil with maximum sulfur content of 0.05 percent by weight.
[PSD-FL-195B]

C.6. Oxides of Nitrogen. Oxides of nitrogen shall not exceed 9.82 grams/hp-hr based on vendor-certified stack test data (or equivalent) on the model of generator purchased. This test data shall be provided to the Department with the initial combustion turbine performance test report.
[PSD-FL-195B]

C.7. This emissions unit is also subject to conditions **H.1** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection D. This section addresses the following emissions unit(s).

Facility ID No.	E. U. ID No.	Brief Description
7775047	-001	Relocatable diesel generator(s) with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generator(s) are uncontrolled.

The generators may be relocated to any of the following facilities:

1. Crystal River Plant, Powerline Road, Red Level, Citrus County.
2. Bartow Plant, Weedon Island, St. Petersburg, Pinellas County.
3. Higgins Plant, Shore Drive, Oldsmar, Pinellas County.
4. Bayboro Plant, 13th Ave. & 2nd St. South, St. Petersburg, Pinellas County.
5. Wildwood Reclamation Facility, State Road 462, 1 mi. east of U.S. 301, Wildwood, Sumter County.
6. Hines Energy Complex, County Road 555, 1 mi. southwest of Homeland, Polk County.
7. Anclote Power Plant, 1729 Baileys Road, Holiday, Pasco County

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Each generator has its own stack. This section of the permit is only applicable when the generator(s) is(are) located at the Hines Energy Complex.}

The following specific conditions apply to the emissions units listed above regardless of location:

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum (combined) heat input rate shall not exceed 25.74 million Btu per hour.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.13.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation - Fuels. Only new No. 2 fuel oil with a maximum sulfur content of 0.5%, by weight, shall be fired in the diesel generator(s).
[Rule 62-213.410, F.A.C. and, AC 09-202080.]

D.4. Hours of Operation. The hours of operation expressed as "engine-hours" shall not exceed 2970 hours in any consecutive 12 month period. The total hours of operation expressed as "engine-hours" shall be the summation of the individual hours of operation of each generator.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AC 09-202080.]

Emission Limitations and Standards

{Permitting Note: The attached Table 1-1, Air Pollutant Emission Allowables and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.5. Visible Emissions. Visible emissions from each generator shall not be equal to or greater than 20 percent opacity, six minute average.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AC 09-202080.]

Excess Emissions

D.6. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and 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.]

D.7. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.8. Fuel Sulfur Analysis. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or permittee upon each fuel delivery. See specific condition **D.3.** and **D.10.**
[Rule 62-213.440, F.A.C.]

Test Methods and Procedures

{Permitting Note: The attached Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.9. The test method for visible emissions shall be EPA Method 9, incorporated and adopted by reference in Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

D.10. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-94, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-95, or the latest edition(s).
[Rules 62-213.440 and 62-297.440, F.A.C.]

D.11. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

D.12. After each relocation, each generator shall be tested within 30 days of startup for opacity and the fuel shall be analyzed for the sulfur content. See specific conditions **D.3.**, **D.5.**, and **D.8.** [Rules 62-4.070(3) and 62-297.310(7)(b),F.A.C.; and, AO 09-205952.]

D.13. Operating Rate During Testing. Testing of emissions shall be conducted with the generator(s) operating at 90 to 100 percent of the maximum fuel firing rate for each generator. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operations may be limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions 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. Failure to submit the actual operating rate may invalidate the test.
[Rules 62-297.310(2), F.A.C.; and, AC 09-202080.]

Recordkeeping and Reporting Requirements

D.14. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, the owner or operator shall notify the Southwest District Air Section, 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 Southwest District Air Section.
[Rule 62-210.700(6), F.A.C.]

D.15. Test Reports.
(a) Each generator shall be tested on an annual basis within 30 days of the date October 25.
(b) 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.
(c) The required test report shall be filed with the Southwest District Office, as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(d) The test reports for a unit that has been relocated shall be submitted to the Southwest District Office.
[Rule 62-297.310(8), F.A.C.; and, AO 09-25952.]

D.16. To demonstrate compliance with specific condition **D.4.**, records shall indicate the daily hours of operation for each of the generators, the daily hours of operation expressed as "engine-hours" and the cumulative total hours of operation expressed as "engine-hours" for each month. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office upon request. The records shall be maintained at each individual site.
[Rules 62-213.440 and 62-297.310(8), F.A.C.; and, AO 09-205952.]

D.17. To demonstrate compliance with specific condition **D.3.**, records of the sulfur content, in percent by weight, of all the fuel burned shall be kept based on either vendor provided as-delivered or as-received fuel sample analysis. The records shall be maintained for a minimum of 5 years and made available to the Southwest District Office upon request. The records shall be maintained at each individual site.
[Rule 62-297.310(8), F.A.C.; and, AC 09-202080.]

Source Obligation

D.18. Specific conditions in construction permit AC 09-202080, limiting the "engine hours", were accepted by the applicant to escape Prevention of Significant Deterioration new source review. If Progress Energy Florida requests a relaxation of any of the federally enforceable emission limits in this permit, the relaxation of limits may be subject to the preconstruction review requirements of Rule 62-212.400(5), F.A.C., as though construction had not yet begun. [Rule 62-212.400(2)(g), F.A.C.; and, AC 09-202080.]

D.19. Progress Energy Florida shall notify the Department's Southwest District Office, in writing, at least 15 days prior to the date on which any diesel generator is to be relocated. The notification shall specify the following;

a. which generator, by serial number, is being relocated,
b. which location the generator is being relocated from and which location it is being relocated to, and
c. the approximate startup date at the new location.

[Rule 62-4.070(3), F.A.C.; and AC 09-202080]

D.20. This emissions unit is also subject to conditions **H.1.** through **H.22., except for H.4,** contained in **Subsection H. Common Conditions.**

Subsection E. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B

Emission units 014 and 015 each consist of a combined cycle Westinghouse 501FD Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 1,915 MMBtu/hr (LHV) while firing natural gas and 2,020 MMBtu/hr (LHV) while firing fuel oil. NO_x emissions are controlled with dry low NO_x burners (DLN) for natural gas firing and wet injection for fuel oil firing, complete with Selective Catalytic Reduction (SCR). Each combustion turbine incorporates an unfired heat recovery steam generator.

{Permitting notes: These emissions unit are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-296A; Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. 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. and PSD-FL-296A]

E.2. Equipment and Controls - 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]

a. Gas Turbine NOx Controls

1. *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.

2. *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.

3. *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.]

b. 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 2A or CT 2B) 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]

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

E.3. 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), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

Emission Limitations and Standards

{Permitting note: Table 1-1, Air Pollutant Emission Allowables and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E.4. Emissions Standards: Emissions from each gas turbine/HRSG shall not exceed the following limits for the listed pollutants at any ambient temperature.

{Permitting note: Unless otherwise specified, the averaging times are based on the specified averaging time of the applicable test method.}

Pollutant	Emission Limit (ppmvd corrected to 15% oxygen)		Averaging Time
	Natural Gas	Fuel Oil	
CO [a]	16	30	24 hour block
NOx [b]	3.5	12	24 hour block
VOC [c]	2	10	3 hours
Ammonia [d]	5	9	3 hours

Pollutant	Fuel Specification and Emission Limit
PM/PM10 [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO2 [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 NO2. 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 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 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 Specific Condition No. **E.3.** of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur 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. **E.3.** of this section effectively limit the potential emissions of SAM and SO2 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 Specific Condition No. **E.18.** 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 = 73.6 lb/hr for natural gas firing and 112 lb/hr for distillate fuel oil firing,*
- *NOx = 25.2 lb/hr for natural gas firing and 93.5 lb/hr for distillate fuel oil firing,*
- *VOC = 4.7 lb/hr for natural gas firing and 22 lb/hr for distillate fuel oil firing,*
- *PM10 = 7.3 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *SO2 = 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 SO2 emissions.} [Rule 62-212.400(BACT), F.A.C.]

[Rules 62-210.200(PTE), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

Excess Emissions

E.5. 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. and PSD-FL-296A]

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

E.6. 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. and PSD-FL-296A]

Monitoring of Operations

E.7. 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), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

E.8. 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 herein.

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 **E.19.** 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), 62-210.700, F.A.C. and PSD-FL-296A]

E.9. 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. [Rule 62-4.070(3), F.A.C. and PSD-FL-296A]

E.10. Tests Required

a. 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]

b. 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.

   1. *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.}*

   2. *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.]

c. 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/PM10 and VOC.}* [Rule 62-212.400 (BACT), F.A.C.]

[PSD-FL-296A]

Test Methods and Procedures

{Permitting note: Table 2-1, Compliance Testing Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

E. 11. 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* 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* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
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]

E. 12. 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), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

Continuous Monitoring Requirements

E.13. 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. E.8. and E.9.

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.]

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E.14. 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), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

E.15. 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), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

Recordkeeping and Reporting Requirements

E.16. Monitoring of Operation: To demonstrate compliance with the fuel consumption limits of this permit, the permittee shall record the distillate fuel oil consumption on a rolling 12-month basis. [Rules 62-4.070(3), 62-212.400, F.A.C., and PSD-FL-296A]

E.17. Frequency of Recordkeeping: Condition **E.12.** 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. and PSD-FL-296A]

E.18. 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.]

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E.19. Malfunction Notification: Within one working day of a malfunction for which CEMS data is excluded pursuant to Condition **E.8.** 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. and PSD-FL-296A]

E.20. 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) and PSD-FL-296A]

E.21. 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.; 40 CFR 60.7(c) and (d) and PSD-FL-296A]

Miscellaneous Conditions

E.22. 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.]

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E.23. These emissions unit are also subject to conditions **H.1.** through **H.22.** contained in **Subsection H. Common Conditions.**

Subsection F. This area reserved for Power Block 3 emissions unit(s).

Subsection G. This area reserved for Power Block 4 emissions unit(s).

Subsection H. Common Conditions.

E.U. ID No.	Brief Description
001	170 MW Westinghouse 501F Combustion Turbine Unit 1
002	170 MW Westinghouse 501F Combustion Turbine Unit 2
014	170 MW Westinghouse 501FD CT2A
015	170 MW Westinghouse 501FD CT2B
003	Auxiliary Steam Boiler
004	Emergency generator with a total fuel consumption limited to 32,000 gallons per year of diesel fuel oil.
7775047, 001	Relocatable diesel generator(s) will have a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts. Emissions from the generator(s) are uncontrolled.

Except as otherwise specified under Subsections A. through G., the following conditions apply to the emissions unit(s) listed above:

Excess Emissions

H.1. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown, or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

H.2. 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.]

H.3. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal

fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard.

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and,

c. Each NESHAP pollutant, if there is an applicable emission standard.

9. 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.

(b) 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 may 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.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 09-205952.]

Test Methods and Procedures

H.4. Operating Rate During Testing. Testing of emissions shall be conducted with the source operating at capacity (maximum heat input rate for the tested operating temperature). Capacity is defined as 90 - 100 percent of permitted capacity. If it is impracticable to test at capacity, then

sources may be tested at less than capacity; in this case subsequent source operation is limited to 110 percent of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen consecutive days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department.
[Rules 62.297.310(2) and (2)(b), F.A.C.]

H.5. Applicable Test Procedures.
(a) Required Sampling Time.
1. 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.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1. (See attachment.)
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

H.6. 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 the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

H.7. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Record Keeping and Reporting Requirements

H.8. Test Reports.
(a) The owner or operator an emissions unit for which a compliance test is required shall file a report with the Department's Central District Office on the results of each such test.
(b) The required test report shall be filed with the Department's Central District Office as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) 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.]

H.9. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District office or the Southwest District Branch office 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's Southwest District office or the Southwest District Branch office.
[Rule 62-210.700(6), F.A.C.]

H.10. Quarterly Report. FPC shall submit a quarterly excess emissions report and monitoring systems performance report. All reports shall be postmarked by the 30th day following the end of each quarter. Written reports of excess emissions shall include the following information:

1. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
2. Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
3. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
4. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)]

H.11. The permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
[40 CFR 60.7(b)]

H.12. Summary Report. The summary report form shall contain the information and be in the format shown in Figure 1 of 40 CFR 60.7(d) unless otherwise specified by the Department. One summary report form shall be submitted for each pollutant monitored.

1. If the total duration of excess emissions for the reporting period is less than one percent of the operating time for the reporting period and CMS downtime for the reporting period is less than five percent of the total operating time for the reporting

period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Department.

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

[40 CFR 60.7 (c) and (d)]

H.13. Reporting Frequency. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), a permittee who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

(i) For 1 year (e.g. 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;

(ii) FPC continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and

(iii) The Department does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after FPC notifies the Department in writing of his or her intention to make such a change and the Department does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Department may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of a FPC conformance with operation and maintenance requirements. Such information may be used by the Department to make a judgement about the source's potential for noncompliance in the future. If the Department disapproves the FPC's request to reduce the frequency of reporting , the Department will notify the permittee in writing within 45 days after receiving notice of FPC's intention. The notification from the Department to the permittee will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the permittee shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with applicable standard for another full year, the permittee may again request approval from the Department to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).

[40 CFR 60.7(e)]

H.14. Records Retention. The permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems

or devices; and, all other information required by 40 CFR 60 recorded in a permanent form suitable for inspection. The file shall be retained for at least **5 (five)** years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7(f); Rule 62-213.440(1)(b)2.b., F.A.C.]

H.15. Credible Evidence. For the purpose of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in 40 CFR 60, nothing in 40 CFR 60 shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed.
[40 CFR 60.11(g)].

Miscellaneous Conditions

H.16. Department Notification. FPC shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted timely and in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and, the anticipated completion date of the change.
[40 CFR 60.8(d)]

Modifications

H.17. Except as provided under 40 CFR 60.14(e) and 40 CFR 60.14(f), any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(a)].

H.18. Emission rate shall be expressed as kg/hr (lbs./hour) of any pollutant discharged into the atmosphere for which a standard is applicable. The Department shall use the following to determine emission rate:

(1) Emission factors as specified in the latest issue of "Compilation of Air Pollutant Emission Factors", EPA Publication No. AP-42, or other emission factors determined by the Department to be superior to AP-42 emission factors, in cases where utilization of emission factors demonstrate that the emission level resulting from the physical or operational change will either clearly increase or clearly not increase.
(2) Material balances, continuous monitor data, or manual emission tests in cases where utilization of emission factors as referenced in 40 CFR 60.14(b)(1) does not demonstrate to the Department's satisfaction whether the emission level resulting from the physical or operational change will either clearly increase or clearly not increase, or where an owner or operator demonstrates to the Department's satisfaction that there are reasonable grounds to dispute the result obtained by the Department utilizing emission factors as referenced in 40 CFR 60.14(b)(1).

When the emission rate is based on results from manual emission tests or continuous monitoring systems, the procedures specified in 40 CFR 60 appendix C of 40 CFR 60 shall be used to determine whether an increase in emission rate has occurred. Tests shall be conducted under such conditions as the Department shall specify to the owner or operator based on representative performance of the facility. At least three valid test runs must be conducted before and at least three after the physical or operational change. All operating parameters which may affect emissions must be held constant to the maximum feasible degree for all test runs.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(b)].

H.19. The addition of an affected facility to a stationary source as an expansion to that source or as a replacement for an existing facility shall not by itself bring within the applicability of 40 CFR 60 any other facility within that source.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(c)].

H.20. The following shall not, by themselves, be considered modifications under 40 CFR 60:
(1) Maintenance, repair, and replacement which the Department determines to be routine for a source category, subject to the provisions of 40 CFR 60.14(c) and 40 CFR 60.15.
(2) An increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on that facility.
(3) An increase in the hours of operation.
(4) Use of an alternative fuel or raw material if, prior to the date any standard under 40 CFR 60 becomes applicable to that source type, as provided by 40 CFR 60.1, the existing facility was designed to accommodate that alternative use. A facility shall be considered to be designed to accommodate an alternative fuel or raw material if that use could be accomplished under the facility's construction specifications as amended prior to the change. Conversion to coal required for energy considerations, as specified in section 111(a)(8) of the Act, shall not be considered a modification.
(5) The addition or use of any system or device whose primary function is the reduction of air pollutants, except when an emission control system is removed or is replaced by a system which the Department determines to be less environmentally beneficial.
(6) The relocation or change in ownership of an existing facility.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(e)].

H.21. Special provisions set forth under an applicable subpart of 40 CFR 60 shall supersede any conflicting provisions of this section.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(f)].

H.22. Within 180 days of the completion of any physical or operational change subject to the control measures specified in 40 CFR 60.14(a), compliance with all applicable standards must be achieved.
[Rule 62-296.800, F.A.C.; and 40 CFR 60.14(g)].

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power Corporation
ORIS code: 7302
Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
-001	170 MW Combined Cycle Westinghouse 501F Combustion Turbine Unit 1
-002	170 MW Combined Cycle Westinghouse 501F Combustion Turbine Unit 2
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.
[Rules 62-213, F.A.C. and 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations and nitrogen oxide (NO_x) requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2002	2003	2004	2005	2006
-001	1A	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*	0*
-002	1B	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*	0*
-014	2A	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*	0*
-015	2B	SO_2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*	0*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track
Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: Phase II Permit received 1/19/99.

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

Appendix I-1, List of Insignificant Emissions Units and/or Activities
Progress Energy Corporation **FINAL** Permit No.: 1050234-008-AV
Hines Energy Complex

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rule 62-210.300(3)(a), F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rule 62.210.300(3)(a), F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. Sand blaster, welding, lathes, hand-held tools, etc.
2. Diesel generator.
3. Fire water tank(s).
4. Brazing, soldering, or welding equipment.
5. Fire and safety equipment.
6. Surface coating operations within a single facility if the total quantity of coatings containing greater than 5.0 percent VOCs, by volume, used is 6.0 gallons per day or less, averaged monthly provided:

a. Such operations are not subject to a volatile organic compound Reasonably Available Control Technology (RACT) requirement of Chapter 62-296, F.A.C.; and

b. The amount of coatings used shall include any solvents and thinners used in the process including those used for cleanup.

NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION

In the Matter of an
Application for Permit Revision by:

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida, Hines Energy Complex
100 Central Avenue BB1A-HE44
St. Petersburg, Florida 33701-5511

FINAL Permit Project No.: 1050234-012-AV
Hines Power Block 2
Polk County

Enclosed is the FINAL Permit, No. 1050234-012-AV, for the Title V Air Operation Revision. The purpose is to incorporate the terms and conditions of the PSD permit which allowed for an increase in heat input relative to the operation of Power Block 2. The facility is located in Polk County. This permit revision is issued pursuant to Chapter 403, Florida Statutes (F.S.). There were no comments received from Region 4, U.S. EPA, regarding the PROPOSED Permit.

Any party to this order (permit revision) has the right to seek judicial review of the permit revision pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; 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 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION (including the FINAL Determination and the relevant pages of the FINAL Permit) was sent by certified mail before the close of business on _____ to the person(s) listed or as otherwise noted:

Roger Zirkle, Plant Manager *

The undersigned duly designated deputy agency clerk hereby certifies that a copy of this NOTICE OF FINAL TITLE V AIR OPERATION PERMIT REVISION was sent by U.S. Mail before the close of business on _____ to the person(s) listed or as otherwise noted:

Dave Meyer, Progress Energy Florida
Scott Osbourn, Golder
Buck Oven, PPSO
Gerald Kissel, Southwest District Office
Gregg Worley, EPA Region 4
John Bunyak, National Park Service

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

_____ _____
(Clerk) (Date)

FINAL Determination

Title V Air Operation Permit Revision
FINAL Permit Project No.: 1050234-012-AV
Progress Energy Florida
Hines Energy Complex, Power Block 2

I. Comment(s).

One comment was received from the applicant, which was to fix an old typographical error in Condition A.1. as well as the description of Power Block 1. As a result, page 7 is being re-issued.

No comments were received from the USEPA during their 45 day review period.

II. Conclusion.

In conclusion, the permitting authority hereby issues the FINAL Permit.

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-001	170 MW Westinghouse 501F Combustion Turbine
-002	170 MW Westinghouse 501F Combustion Turbine

Emission units 001 and 002 each consist of a combined cycle Westinghouse 501F Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of 1,915 mmBtu/hr (HHV) while firing natural gas and 2,020 MMBtu/hr (HHV) while firing fuel oil. NO_x emissions are controlled with dry low NO_x burners (DLN) and/or Selective Catalytic Reduction (SCR) for natural gas firing and wet injection for fuel oil firing. Each combustion turbine incorporates an unfired heat recovery steam generator.

{Permitting notes: These emission units are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-195B; and Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. At an ambient temperature of 59 °F, each combustion turbine shall not exceed 1,915 MMBtu/hr (HHV) while firing natural gas, or 2,020 MMBtu/hr (HHV) while firing fuel oil. See Attachment **G-1** for a plot of heat input versus temperature.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and PSD-FL-195B]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **E.4.**

A.3. Methods of Operation - (i.e., Fuels). Only natural gas, having a maximum sulfur content of 1 grain per 100 cf of natural gas, or low sulfur fuel oil having a maximum sulfur content of 0.05%, by weight, shall be fired in each combustion turbine at all times. The maximum allowable fuel oil consumption for the two turbines is 13,762,806 gallons per year, which is equivalent to an aggregate of 1,000 hours per year of operation at full load.
[Rule 62-213.410, F.A.C.]

A.4. Hours of Operation. Each of the combustion turbines in Power Block 1 may operate continuously, i.e., 8,760 hours/year.

Subsection E. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B

Emission units 014 and 015 each consist of a combined cycle Westinghouse 501FD Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of ~~1,915~~ 2,048 MMBtu/hr (~~L~~HHV) while firing natural gas and ~~2,020~~ 2,155 MMBtu/hr (~~L~~HHV) while firing fuel oil. NO_x emissions are controlled with dry low NO_x burners (DLN) for natural gas firing and wet injection for fuel oil firing, complete with Selective Catalytic Reduction (SCR). Each combustion turbine incorporates an unfired heat recovery steam generator.

{Permitting notes: These emission units are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-296A; and Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. The maximum heat input rate to each gas turbine is ~~1,915~~ 2,048 MMBtu per hour when firing natural gas and ~~2,020~~ 2,155 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. and PSD-FL-296A]

E.2. Equipment and Controls - 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]

a. Gas Turbine NOx Controls

1. *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.

d. Subject to the requirements 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 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 Specific Condition No. **E.3.** of this section combined with the efficient combustion design and operation of each gas turbine represents the BACT determination for PM/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur 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. **E.3.** of this section effectively limit the potential emissions of SAM and SO2 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 Specific Condition No. **E.18.** 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 =~~73.6~~ 78.7 lb/hr for natural gas firing and ~~112~~ 119.5 lb/hr for distillate fuel oil firing,*
- *NOx = ~~25.2~~ 27.0 lb/hr for natural gas firing and ~~93.5~~ 99.7 lb/hr for distillate fuel oil firing,*
- *VOC = ~~4.7~~ 5.0 lb/hr for natural gas firing and ~~22~~ 23.5 lb/hr for distillate fuel oil firing,*
- *PM10 = 7.3 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *SO2 = 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 SO2 emissions.} [Rule 62-212.400(BACT), F.A.C.]

[Rules 62-210.200(PTE), 62-212.400(BACT), F.A.C. and PSD-FL-296A]

Excess Emissions

E.5. 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. and PSD-FL-296A]

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

E.6. 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. and PSD-FL-296A]

February 11, 2005

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Roger Zirkle, Plant Manager
Progress Energy Florida -Hines Energy Complex
100 Central Avenue, CX1B
St. Petersburg, Florida 33701

Re: Project No. 1050234-011-AC: Revision of Permit No. PSD-FL-296
Project No. 1050234-013-AC: Revision of Permit No. PSD-FL-330
Project No. 1050234-012-AV: Revision of Title V Air Operation Permit

The applicant, Progress Energy Florida, applied on February 1, 2005, to the Department for a modification to PSD Permit numbers PSD-FL-296, PSD-FL-330 for its Hines Energy Complex located in Polk County. The modification is to allow the facility to utilize the fully installed capacity of the Power Block 2 and 3 combined cycle units by modifying the maximum heat input ratings. The Department has reviewed the modification request. The referenced permits are hereby modified as follows:

For PSD permit PSD-FL-296 (Section III), changes are as follows:

3. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value of the fuels, and an ambient air temperature of 59 °F, shall not exceed ~~1915~~ 2048 mmBtu/hr when firing gas and ~~2020~~ 2155 mmBtu/hr when firing distillate fuel oil. This maximum heat input rate will vary depending upon ambient conditions and the combustion turbine characteristics that are described by the manufacturer's curves required by condition 6 of this section. Operation of these emissions units at less than 60% of capacity (based on heat input rates) is not allowed, except as required to cycle the units through periods of startup, shutdown and malfunction. The terms startup, shutdown and malfunction are defined at Rule 62-210.200, F.A.C. [Rules 62-4.070(3) and 62-210.200, F.A.C., limitation on potential to emit]

For PSD permit PSD-FL-330 (Section III), changes are as follows:

7. Permitted Capacity - Gas Turbines: The maximum heat input rate to each gas turbine is ~~1,915~~ 2,048 MMBtu per hour when firing natural gas and ~~2,020~~ 2,155 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.]

Additionally, corresponding changes are required to the Title V Air Operation permit (1050234-012-AV). These changes are attached as revised page 24 of the subject permit. All other conditions of the referenced permits remain unchanged. A copy of this letter shall be filed with the referenced permit and shall become part of the permit.

Executed in Tallahassee, Florida.

Michael G. Cooke, Director
Division of Air Resource
Management

Subsection E. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B

Emission units 014 and 015 each consist of a combined cycle Westinghouse 501FD Combustion Turbine, each with a nominal generator rating of 170 MW and each with a maximum heat input rating of ~~1,915~~ 2,048 MMBtu/hr (LHV) while firing natural gas and ~~2,020~~ 2,155 MMBtu/hr (LHV) while firing fuel oil. NO_x emissions are controlled with dry low NO_x burners (DLN) for natural gas firing and wet injection for fuel oil firing, complete with Selective Catalytic Reduction (SCR). Each combustion turbine incorporates an unfired heat recovery steam generator.

{Permitting notes: These emissions unit are regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); PSD-FL-296A; Rule 62-212.400(6), F.A.C.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

E.1. Permitted Capacity. The maximum heat input rate to each gas turbine is ~~1,915~~ 2,048 MMBtu per hour when firing natural gas and ~~2,020~~ 2,155 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. and PSD-FL-296A]

E.2. Equipment and Controls - 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]

a. Gas Turbine NOx Controls

1. *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.

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 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 _____ 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.

_____ _____
(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.

Condition No. 4: 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.

Condition No. 9: 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."

Condition No. 13(d), 13(e), 20(g), and 26: 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.

Condition No. 20(a) and 20(b): 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.

Condition No. 20(a) and 20(b): 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.

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 Cooke, Director (Date)
Division of Air Resources Management

(1)

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/PM10), 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)

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/PM10, 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/PM10, 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

(1)

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.

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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/PM10 [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO2 [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 NO2. 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/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur 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 SO2 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.

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{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* 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* The test shall be conducted for a minimum of 30 minutes.
10	*Determination of Carbon Monoxide Emissions from Stationary Sources* This method shall be based on a continuous sampling train.
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/PM10 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

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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)]

SECTION IV. APPENDICES

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.

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/PM10), 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.

BACT for CO Emissions

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.

BACT for NOx Emissions

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.

BACT for VOC Emissions

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 (≤ 1.0 grains of sulfur per 100 standard cubic feet of natural gas) and restricted use of very low sulfur distillate oil (≤ 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.

...ant	Emission Limit (ppmvd corrected to 15% oxygen)		...e
	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	ion and Emission Limit
PM/PM10 [e]	Fuel specifications. Visible emissions shall not exceed 10% opacity for each 6-minute block average.
SAM/SO2 [f]	Fuel specifications.

g. 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.}*

h. 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 NO2. 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.}*

i. 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.

j. 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.

k. 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/PM10 emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

l. The fuel sulfur specifications in Condition No. 8 of Section III of this permit effectively limit the potential emissions of SAM and SO2 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,*
- *PM10 = 8.5 lb/hr for natural gas firing and 64.8 lb/hr for distillate fuel oil firing, and*
- *SO2 = 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 SO2 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/PM10, SAM, SO2, 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:

Trina Vielhauer, Chief
Bureau of Air Regulation

Approved By:

Michael Cooke, Director
Division of Air Resources Management

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.

SECTION IV. APPENDIX GC

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

(1)

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.

(1)

[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.

(1)

§ 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

(1)

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.]

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*: _____

SECTION IV. APPENDIX YYYY

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.]

ATTACHMENT PEF-FI-CV3

COMPLIANCE REPORT AND PLAN

Department of Environmental Protection

Division of Air Resources Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

Facility Owner/Company Name: Florida Power Corporation

Site Name: Hines Energy Complex County: Polk

Title V Air Operation Permit No.: 1050234-012-AV

REPORTING PERIOD	REPORT DEADLINE*
January 1 through December 31 of 2005 (year)	March 1, 2006

*See Rule 62-213.440(3)(a)2, F.A.C.

COMPLIANCE STATEMENT (Check only one of the following three options)

____ **A.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

__x__ **B.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

____ **C.** This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number.
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

Martin J. Drango — *(Signature of Title V Source Responsible Official)*

2/27/06 — *(Date)*

Name: Martin J. Drango, P.E. Title: Plant Manager

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

I, the undersigned, am authorized to make this submission on behalf of the owners and operators of the Acid Rain source or Acid Rain units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

J. M. Kennedy — *(Signature of Acid Rain Source Designated Representative)*

2/27/06 — *(Date)*

Name: J. Michael Kennedy Title: Principal Environmental Specialist

{Note: Attachments, if required, are created by the responsible official or the designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by the responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. EPA (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

Progress Energy Florida
Hines Energy Complex - **PB1**
Deviations from Permit Conditions

During January 1st to June 30th 2005, there were no deviations for Unit 1B. This was previously summarized in the quarterly excess emissions reports.

Date	Time	Duration	Parameter	Description

No deviations for Unit 1A or 1B.

Progress Energy Florida
Hines Energy Complex – **PB2**
Deviations From Permit Conditions

During January 1st to June 30th 2005, the following deviations occurred for Unit **2A.** These were previously summarized in the quarterly excess emissions reports.

Date	Time	Duration	Parameter	Description
4/25/05	0800-1200	5 hours	NOx, CO	Prior noticed tuning session

During January 1st to June 30th 2005, the following deviations occurred for Unit **2B.** These were previously summarized in the quarterly excess emissions reports.

Date	Time	Duration	Parameter	Description
4/25/05	0800-1200	5 hours	NOx, CO	Prior noticed tuning session
4/27/05	0500, 0600	2 hours	CO	Flash-back
6/6/05	1400, 1500	2 hours	NOx, CO	Circuit breaker trip due to a lifted exhaust thermocouple

Progress Energy Florida
Hines Energy Complex - **PB1**
Deviations from Permit Conditions

During July 1st to December 31st 2005, there were no deviations for Unit 1B. This was previously summarized in the quarterly excess emissions reports.

Date	Time	Duration	Parameter	Description

No deviations for Unit 1A or 1B.

Progress Energy Florida
Hines Energy Complex – **PB2**
Deviations from Permit Conditions

During July 1st to December 31st 2005, the following deviations occurred for Unit **2A**. These were previously summarized in the quarterly excess emissions reports.

Date	Time	Duration	Parameter	Description
11/05/05	0900	1 hour	NOx, CO	Fuel swap
11/05/05	1000	2 hours	NOx, CO	Prior noticed tuning session

During July 1st to December 31st 2005, the following deviation occurred for Unit **2B**. This was previously summarized in the quarterly excess emissions report.

Date	Time	Duration	Parameter	Description
10/31/05	1200	1 hour	NOx	Prior noticed tuning session

For a period of approximately 151 hours during August 4-10, 2005, there was an incorrect fuel gas mass flow signal due to a loose wire that connects the thermocouple to the Flow Boss. The wire was tightened and the signal read correctly. Data substitution

was used for the EDR submittal during the time that the fuel flow gas signal was inoperable.

Progress Energy Florida
Hines Energy Complex – **PB3**
Deviations from Permit Conditions
Air Construction Permit 1050234-006-AC/PSD-FL-330

During July 1st to December 31st 2005, the following deviations occurred for Unit **3A**. This was previously summarized in the quarterly excess emissions report.

Date	Time	Duration	Parameter	Description
11/04/05	1800	1 hour	NOx, CO	Malfunction (not reported)

During July 1st to December 31st 2005, the following deviations occurred for Unit **3B**. This was previously summarized in the quarterly excess emissions report.

Date	Time	Duration	Parameter	Description
11/06/05	0900	1 hour	CO	Malfunction
12/12/05	0900	1 hour	NOx,	Malfunction

ATTACHMENT PEF-FI-CV6

REQUESTED CHANGES TO CURRENT TITLE V AIR OPERATION PERMIT

Florida Power Corporation dba Progress Energy Florida, Inc.
Hines Energy Complex
Facility ID: 1050234
Title V Permit Renewal and Title V Permit Revision
Permit Language Corrections and Updates
April 20, 2006

Below includes suggested permit language to correct previous errors or clarify existing language. The changes are shown via ***bold italics*** for additions and ~~strikethrough~~ for deletions.

E.U. ID No.	Brief Description
-001	170 MW Westinghouse 501F Combustion Turbine
-002	170 MW Westinghouse 501F Combustion Turbine

A.7. Excess emissions resulting from startup, shutdown, malfunction, ***fuel switch*** or load change shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period except in the event that the steam turbine has been shut down for 8 hours or more. During a cold start-up to combined cycle operation, up to ***six*** ~~four~~ hours of excess emissions are allowed in a 24-hour period. Cold start-up is defined as a start-up to combined cycle operation following a steam turbine shutdown of greater than 48 hours. During a warm start up to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine of greater than 8 hours and less than 48 hours. ***During fuel switch, up to four hours of excess emissions are allowed in a 24-hour period.***
[Applicant Request, Vendor Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]
{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

Comment [i1]: Clarifies the number of excess emissions allowed for fuel switching. This activity will be needed in preparation of fuel curtailment such as a result of hurricanes.

A.11. The permittee shall monitor sulfur content and nitrogen content of the new No. 2 distillate fuel oil and sulfur content of natural gas. These values may be provided by the vendor and the frequency of determinations of these values shall be as follows:

a. New No. 2 Distillate Fuel Oil. The values, sulfur and nitrogen content, shall be determined on each occasion that fuel is transferred to the storage tanks from any other source. Records of these values shall be kept by the facility for a five year period for regulatory agency inspection purposes.

b. Natural Gas. Pursuant to ***40 CFR 60 Subpart GG*** ~~40 CFR 60.334(b)(2)~~, a custom fuel monitoring schedule for the determination of these values shall be followed for the natural gas fired at this facility and shall be as follows:

Comment [i2]: Through out this document suggested language is inserted to clarify the ASTM methods to be used for sulfur content analysis. This will allow for changes to the 40 CFR Subpart GG during the life of the Title V Permit.

Custom Fuel Monitoring Schedule for Natural Gas (NG)

1. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the gas turbines.
2. Sulfur Monitoring:
   (a). Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an

approved alternative method. The*se* ~~reference~~ methods are ~~ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as~~ referenced in ~~40 CFR 60.335(b)(2),~~ ***40 CFR 60 Subpart GG. The permittee can use these methods or*** the*ir* latest edition(s).

(b). This custom fuel monitoring schedule ~~shall become~~ became effective on the date ~~this permit becomes~~ ***the Initial Title V Permit became*** valid. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333 and the conditions of this permit, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein the applicant may begin monitoring as per the requirements of 2(c).

(c). If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333 and the conditions of this permit, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(d). Should any sulfur analysis as required in items 2(b) or 2(c) above indicate non-compliance with 40 CFR 60.333 and the conditions of this permit, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

Comment [I3]: Clarifies that the permittee had already completed the fuel monitoring schedule and is meeting the twice per six month requirement.

3. If there is a change in fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in natural gas quality (i.e., sulfur content varying by more than ~~10 grains/1000~~ ***1 grain per 100 standard cubic feet*** of gas) shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

Comment [I4]: Correct a typo.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

[***7-1-05 Edition of 40 CFR 60.334(i)(3), 40 CFR 60. 334(h), and 40 CFR 60.335(b)*** ~~40 CFR 60.334(b)~~; PSD-FL-195B; and, Custom Fuel Monitoring Schedule Approved on June 1, 2000.]

A. 12. Critical Fuel Parameters. The maximum sulfur content of the low sulfur fuel oil shall not exceed 0.05 percent by weight. Compliance shall be demonstrated in accordance with the requirements of ~~40 CFR 60.334~~ ***40 CFR 60 Subpart GG*** testing for sulfur content of the fuel oil in the storage tanks on each occasion that fuel is transferred to the storage tanks from any other source. Testing for fuel bound nitrogen content ***per 40 CFR Subpart GG*** ~~by ASTM D3431 or D4629 or other equivalent ASTM method~~, and for fuel oil higher heating value, shall also be conducted on the same schedule.

[~~40 CFR 60.334(b)~~ ***7-1-05 Edition of 40 CFR 60.334(i)(1)***]

A.15. Sulfur Dioxide. The permittee shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) ***by using the ASTM reference methods in 40 CFR 60, Subpart GG or their latest editions*** ~~as follows:~~

~~ASTM D 4294 (or equivalent) for sulfur content of distillate oil, and;~~

~~ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 (or equivalent) for sulfur content of natural gas.~~
[*7-1-05 Edition of 40 CFR 60. 334(h(1) and 40 CFR 60.335(b)(10);* Rules 62-297.440, and 62-297.620(2)(d), F.A.C.; ~~and~~ PSD-FL-195B]

A.20. To meet the requirements of ***40 CFR 60 Subpart GG*** ~~40 CFR 60.334(b)~~, the permittee shall use the methods specified in 40 CFR 60.***334 and 40 CFR 60.***335~~(a) and (d)~~ to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency.
[~~40 CFR 60.335(e)~~ ***7-1-05 Edition of 40 CFR 60.335(11)***]

E.U. ID No.	Brief Description
-014	170 MW Westinghouse 501FD CT2A
-015	170 MW Westinghouse 501FD CT2B

E.8. CEMS Data Exclusion: As provided in this paragraph, NO_x 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 herein.

a. Periods of data excluded for startup shall not exceed two hours in any 24-hour block except for cold ***and warm*** startups. A "cold startup" is defined as a startup ***to combined cycle operation*** following a complete ***steam turbine or combustion turbine*** shutdown lasting a minimum of 48 hours. Periods of data excluded for cold startup shall not exceed ~~four~~ ***six*** hours in any 24-hour block period. ***During a warm start up to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine of greater than 8 hours and less than 48 hours.***

Comment [i5]: This would provide for reliable operation as required by the Energy Control Center.

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~~ ***four*** 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 **E.19.** 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~~ ***eight*** hours in any 24-hour block period during which a cold startup occurred ***and shall not exceed 7 hours in any 24-hour 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.

Comment [i6]: In preparation for emergency situations such as fuel curtailment as a result of hurricanes, PEF will need the option to test the operation of fuel switching one to two times per month.

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), 62-210.700, F.A.C. and PSD-FL-296A]

E.9. 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, ***process controls adjustment,*** 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.
[Rule 62-4.070(3), F.A.C. and PSD-FL-296A]

Comment [I7]: Process controls adjustment could require tuning of the unit.

E.18. 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 ***in 40 CFR 60, Subpart GG or their latest editions*** ~~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.~~ ***Sampling and analysis for the fuel oil sulfur content shall be conducted using the ASTM methods in 40 CFR 60, Subpart GG.*** 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.; ***7-1-05 Edition of 40 CFR 60.334 and 40 CFR 60.335;***][PSD-FL-296A]

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Power Block 1 consists of two identical Westinghoues 501F combined cycle combustion turbines firing natural gas with distillate oil backup.

3. Emissions Unit Identification Number: **001, 002**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 F**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Generator nameplate rating given for one CT. Total Power Block 1 generating capacity of approximately 500 MW, including two 170 MW each CTs and 160 MW steam turbine electrical generator.

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Dry Low NO_x combustion - natural gas firing.

   Selective Catalytic Reduction (SCR) – natural gas firing.

   Water Injection – distillate oil firing.

2. Control Device or Method Code(s): **025, 065, 028**

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **1,915** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24**hours/day **52**weeks/year	**7**days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input is higher heating value (HHV) with natural gas; heat input at 59°F turbine inlet temperature. The maximum heat input rate for fuel oil is 2,020 MMBtu/hr (HHV) at 59°F turbine inlet temperature.**	

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT1A, CT1B**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each combustion turbine exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190**°F	9. Actual Volumetric Flow Rate: **1,009,487** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet.**		

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.91**	5. Maximum Annual Rate: **16,286.8**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**
10. Segment Comment: **Per CT, based on 1,030 BTU/CF (HHV); maximum hourly at 30°F, 1,970 MMbtu/hr; annual at 59°F, 1,915 MMBtu/hr. See Title V Permit No. 1050234-001-AV, Attachment G-1 for plot of heat input versus temperature.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **14.55**	5. Maximum Annual Rate: **13,762.806**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment: **Per CT, BTU based on HHV of 141.2 MMBtu/1,000 gallons; maximum hourly at 30°F, 2,054 MMbtu/hr Aggregate annual fuel usage of 13,762,806 gallons per year for Power Block 1. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.**		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	065	EL
CO			EL
VOC			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **44.8** lb/hour **75.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 59°F turbine inlet; TPY with 8,260 hr/yr-gas; equivalent of 500 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **15.6** lb/hour **68.3** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-195B. Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20% Opacity**	4. Equivalent Allowable Emissions: **44.8** lb/hour **11.2** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-195B, Title V Permit No 1050234-001-AV, 500 hr/yr/CT**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **94** lb/hour **42.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 59°F turbine inlet; TPY with 8,260 hr/yr-gas; equivalent of 500 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas – 1 grain S/100 scf**	4. Equivalent Allowable Emissions: **4.7** lb/hour **22** tons/year
5. Method of Compliance: **Fuel Sampling – Vendor or Permittee**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-195B, Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **94** lb/hour **23.5** tons/year
5. Method of Compliance: **Fuel Sampling – Vendor or Permittee.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: 500 hr/yr/CT. PSD-FL-195B, Title V Permit No 1050234-001-AV.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **305** lb/hour **377.7** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 59°F turbine inlet; TPY with 8,260 hr/yr-gas; equivalent of 500 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **73** lb/hour **319.7** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-195B, Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **42 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **305** lb/hour **76.3** tons/year
5. Method of Compliance: **CEM Part 75; 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-195B, Title V Permit No 1050234-001-AV , 500 hr/yr/CT**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **93** lb/hour **341.3** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing; TPY with 8,260 hr/yr-gas and 500 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **77** lb/hour **337.3** tons/year
5. Method of Compliance: **Annual Test: EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-195B. Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **30 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **93** lb/hour **23.3** tons/year
5. Method of Compliance: **Annual Test: EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-195B, Title V Permit No 1050234-001-AV , 500 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **19** lb/hour **47.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 59°F turbine inlet; TPY with 8,260 hr/yr-gas; equivalent of 500 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **7 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **10.4** lb/hour **45.6** tons/year
5. Method of Compliance: **Initial Test – EPA Method 18 or 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-195B. Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **19.0**lb/hour **4.75** tons/year
5. Method of Compliance: **Initial Test – EPA Method 18 or 25A**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-195B, Title V Permit No 1050234-001-AV. 500 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Gas Firing. Title V Permit 1050234-008-AV, Condition A.5.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Oil Firing. Title V Permit 1050234-008-AV, Condition A.5.**	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **Title V Permit No. 1050234-008-AV, Condition A.7. Excess emissions resulting from startup, shutdown, malfunction, or load change shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period except in the event that the steam turbine has been shut down for 8 hours or more. During a cold start-up to combined cycle operation, up to four hours of excess emissions are allowed in a 24-hour period. Cold start-up is defined as a start-up to combined cycle operation following a steam turbine shutdown of greater than 48 hours. During a warm start up to combined cycle operation, up to three hours of excess emissions are allowed in a 24-hour period. Warm start-up is defined as a startup to combined cycle operation following a steam turbine of greater than 8 hours and less than 48 hours.** **[Applicant Request, Vendor Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.]** **{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}**	

Visible Emissions Limitation: Visible Emissions Limitation _ of

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TEI (CT1A, CT1B)** Model Number: **42C(CT1A, CT1B)** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT1A: 42C-58559-318. Serial No. for CT1B: 42C-58558-318.** **Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_x CEM in lieu of WTF monitoring. 40 CFR 75. PSD-FL-195B.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **CO_2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **CAI (CT1A, CT1B)** Model Number: **ZRH1 (CT1A, CT1B)** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT1A: N6M 0531T. Serial No. for CT1B: N6M 0528T.** **See NOx.**	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I2** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I3** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☒ Attached, Document ID: **PEF-EU1-I6**
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [1] of [5]
Power Block 1

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: ____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: ____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: **PEF-EU1-IV1** ☐ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: ____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: **PEF-EU1-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: ____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID: **PEF-EU1-IV5**
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: ____
      ☐ Previously Submitted, Date: ____
   ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT PEF-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT PEF-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

Natural Gas:

Average analysis of natural gas (volume %)

CO_2	0
N_2	5.15
O_2	0
CH_4	81.11
C_2H_6	9.665
C_3H_8	3.505
i-C_4H_{10}	0.19
n-C_4H_{10}	0.24
C_5+	0.09
C_6+	0.05
	100

Maximum sulfur content is typically 1 gr/100 scf

Average gross heating value = 1,030 Btu/ft^3

ATTACHMENT PEF-EU5-I2

DIESEL FUEL ANALYSIS

Typical Properties of Diesel Fuel:

Property	ASTM Test Method	Grade No. 2-Diesel
Flash Point, ° C. min.	D 93	52
Water & Sediment, % vol, max	D 2709	0.05
	D 1796	...
Distillation Temperature, ° C 90 % % vol Recovered	D 86	
min		282
max		338
Kinematic Viscosity, mm2/S at 40° C	D 445	
min		1.9
max		4.1
Ash % mass, max	D 482	0.01
Sulfur, % mass, max	D 2622	...
	D 129	0.05
Copper strip corrosion rating max 3 h at 50° C	D 130	No. 3
Cetane number, min	D 613	40
One of the following properties must be met:		...
(1) Cetane index, min	D 976	...
(2) Aromaticity, 5 vol. max	D 1319	A
Operability Requirements	D 2500	
Cloud Point, °C, max	D 4539/	
or	D 6371	
LTFT/CFPP, °C, max	D 2500	
Ramsbottom carbon residue on 10% distillation residue, % mass, max	D 524	0.35

ATTACHMENT PEF-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT PEF-EU1-I3

DESCRIPTION OF CONTROL EQUIPMENT

Dry Low NOx (DLN) Combustion: DLN combustion system is used to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required by each gas turbine, the DLN combustors and automated gas turbine control system were tuned in accordance with Siemens Westinghouse requirements, in conjunction with the selective catalytic reduction emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with Siemens Westinghouse recommendations.

Water Injection: Water injection system is used to deduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required by each gas turbine, the water injection systems were tuned in accordance with Siemens Westinghouse requirements, in conjunction with the selective catalytic reduction emissions control equipment, to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with Siemens Westinghouse recommendations.

In accordance with Siemens Westinghouse specifications, a monitoring system is maintained to continuously measure and record the water-to-fuel ratio when firing distillate oil

SCR System: A SCR system is used to control NOx emissions from each gas turbine when firing either natural gas or distillate oil. The SCR system consists of the following components:

- Ammonia injection grid
- Catalyst
- Ammonia storage
- Monitoring equipment
- Control system
- Electrical system
- Piping
- And other ancillary equipment

The SCR is designed and constructed according to achieve the permitted level of NOx emissions and ammonia slip.

Ammonia injection is initiated as soon as the operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacture. In accordance with the SCR manufacture specifications, a ammonia flow meter is maintained to measure and record the ammonia injection rate to the SCR system.

ATTACHMENT PEF-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN & OPERATION AND MAINTENANCE PLAN

ATTACHMENT PEF-EU1-I4

PROCEDURES OF STARTUP & SHUTDOWN AND OPERATION & MAINTENANCE PLAN

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) maintains detailed procedures for startup, shutdown and operation and maintenance for all power blocks at the Hines Energy Complex. These procedures are available upon request. The following is a general description of these activities.

STARTUP/SHUTDOWN

In general for startup, the control logic for the Siemens Westinghouse single steam turbine-electrical generator has a set startup ramp rate and hold points. The ramp rate and hold points are in place to control the thermal stress of the turbine casting. In addition the steam turbine must be warmed up at a slow rate so the rotating turbine does not expand faster than the shell – keeping the rotating rotor from hitting the stationary shell. The ramp rate and hold points are fixed in the Siemens Westinghouse software and cannot be changed by the operators.

The startup ramp rate and hold points on the Westinghouse single steam turbine-electrical generator require that the combustion turbines limit the heat to the Heat Recovery Stream Generator (HRSG) during startup.

OPERATION

In the natural gas-fired mode, the dry low NO_x control system regulates the distribution of fuel delivered to a multi-nozzle, total premix combustor arrangement. The fuel flow distribution to each combustion chamber fuel nozzle assembly is calculated to maintain unit load and fuel split for optimal turbine emissions.

During distillate fuel oil combustion, the liquid fuel (distillate oil) system filters, pressurizes, controls, and equally distributes fuel flow to the turbine combustion chambers.

MAINTENANCE

Maintenance is performed in accordance with Siemens Westinghouse recommendations and PEF guidelines.

The above general description of procedures for startup, shutdown, operation, and maintenance is presented as an example of the procedures performed and maintained at the facility. The actual procedures followed may vary from the description indicated above.

ATTACHMENT PEF-EU1-I6

COMPLIANCE DEMONSTRATION REPORTS

Air Emissions Compliance Test Report

Progress Energy Florida
Hines Energy Complex, Units 1A and 1B
Bartow, Florida

C.E.M. Solutions Project No. 2454

Testing Completed: September 2005

Client Purchase Order Number: 49782
C.E.M. Solutions, Inc Report Number: 20-2454-01-001

C.E.M. Solutions, Inc.
7990 W. Gulf to Lake Hwy.
Crystal River, Florida 34429
Phone: 352-564-0441

Project Background

Name of Source Owner:	Progress Energy Florida
Address of Owner:	One Power Plaza 263 13th Avenue South St. Petersburg, Florida 33701
Source Identification:	Oris Code: 7302 Facility ID: 1050234 Emissions Unit: -001, -002
Location of Source:	Polk County, Florida
Type of Operation:	SIC Code: 4911
Tests Performed:	Method 3A - Determination of Oxygen and Carbon Dioxide Method 7E - Determination of Nitrogen Oxides Method 9 - Visual Determination of Opacity Method 10 - Determination of Carbon Monoxide Method 19 - Determination of Nitrogen Oxide Emissions Rates ASTM D-240 - Fuel Analysis (by others) ASTM D-1552 - Sulfur in Petroleum Products (by others)
Test Supervisor:	Mr. Jeremy A. Johnson
Date(s) Tests Conducted:	Units 1A and 1B: September 27, 2005
Site Test Coordinator:	Mr. James T. Long
State Regulatory Observers:	No Observers Present

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Appendices

1.0 Introduction

Progress Energy, Florida (PEF) retained C.E.M. Solutions, Inc. to perform source emissions testing on Units 1A and 1B stationary combustion turbines located at its Hines Energy Complex in Bartow, Florida.

The test program was conducted in order to evaluate the compliance status of Unit 1A and 1B exhaust while firing Pipeline Natural Gas (PNG), in respect to the United States Environmental Protection Agency (USEPA) Standards of Performance for Stationary Turbines (Title 40 of the Code of Federal Regulations, Part 60, Subpart GG) and the Florida Department of Environmental Protection's (FDEP's) permit number 1050234-012-AV. The test program and results are presented and discussed in this report.

James T. Long of Progress Energy's Environmental Services Section coordinated plant operations throughout the test program.

All testing was conducted in accordance with test methods promulgated by the USEPA.

2.0 Facility Description

The Hines Units 1A and 1B are Westinghouse 501F Combustion Turbine models having a nominal generating capacity of 170 MW and are all capable of firing natural gas or distillate oil.

2.1 Process Equipment

Units 1A and 1B each have a maximum heat input rating that shall not exceed 1,915 million Btu per hour (mmBtu/hr) when firing natural gas and 2,020 on distillate oil. Heat inputs are based on the High Heating Value (HHV) of each fuel.

Control measures and equipment consists of dry low NO_x burners and Selective Catalytic Reduction. Each combustion turbine incorporates an unfired heat recovery steam generator. Emissions are exhausted through separate 110 ft. stacks, each having an inner diameter of 19 ft.

2.2 Regulatory Requirements

PEF is required to conduct annual emissions tests for the following pollutants while operating at 90-100 percent of the heat input curve. Emission testing was conducted to determine the compliance status of the following pollutants:

- NO_X (demonstrated by CEMS Relative Accuracy Test Audit)
- SO_2 in % S by weight of fuel
- CO in ppmvd and pounds per hour
- Opacity in percent

Table 1 summarizes the applicable emissions limits for Unit 1A and 1B.

Table 1: Summary of Emissions Limits
Progress Energy Florida
Hines Energy Complex
Units 1A and 1B

Pollutant	Emission Limit	Permit Condition
Visual Emission	≤10% for PNG	A.5
CO	25 ppmvd and 77.0 lbs/hr for PNG	A.5
SO_2 and H_2SO_4	1 grain/100 dscf for PNG	A.5
NO_X	≤10% Error on CEMS RATA	A.5.a

3.0 Test Program/Operating Conditions

Emissions tests were completed on Units 1A and 1B at the Hines Energy Complex to determine the compliance status of the fuel turbines on September 27, 2005.

CO and Opacity compliance testing was performed concurrently with 40CFR, Part 75 Relative Accuracy Testing conducted on Units 1A and 1B CEMS NO_X analyzers, at high load, while firing PNG.

Units 1A and 1B SO_2 emissions were calculated from fuel analysis and fuel flow rates while each unit was operating at high load.

Turbine operating data was collected and provided by facility personnel during the entire test program. Data provided include, but was not limited to, the following:

- Unit Generation (MW)
- Combustor inlet air temperature (°F)
- Fuel flow rate

Table 2 summarizes the heat input for each unit during the compliance tests.

Table 2: Summary of Heat Inputs
Progress Energy Florida
Hines Energy Complex
Units 1A and 1B

Unit	Fuel	Heat Input (mmBtu/hr)	Inlet Temperature (°F)	Maximum HHI @ Temp.	Percent of Maximum Heat Input
1A	Gas	1695	75.28	1865	90.9%
1B	Gas	1704	77.14	1859	91.7%

Units 1A and 1B operating data and heat input curves can be viewed in Appendix A.

Heat input calculations are on the compliance summaries located in Appendix I.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

4.1 Instrument Analyzer Procedures

Units 1A and 1B CO reference method (RM) data was determined using instrument analyzer procedures. In addition, diluent gas concentrations of oxygen (O_2) were also measured via instrumental methods.

NO_X RM data was determined using instrument analyzer procedures as well. NO_X EPA Method 7E was used for a Relative Accuracy Test Audit (RATA) on the Units 1A and 1B CEMS NO_X analyzers. CO_2 data was also used to calculate NO_X pollutant emissions pounds per million Btu.

Mathematical equations used to determine calculated emissions standards are located in Appendix B.

RM gaseous compliance summaries and raw data are located in Appendix F.

RATA results and supporting RM and CEMS data can be viewed in Appendix G.

Table 3 summarizes the EPA methods and instrumentation:

Table 3: Summary of EPA Instrument Reference Methods
Progress Energy Florida
Hines Energy Complex
Units 1A and 1B

Unit/Pollutant	Fuel	EPA Method	Instrument	Serial Number
1A/NO_X	Gas	7E	TEI Model 42CHL	42CHL-74122-375
1A/ CO_2	Gas	3A	Servomex	1415D/3379
1A/O_2	Gas	3A	Servomex	1420D/3379
1A/CO	Gas	10	TEI Model 48C	48C-74094-375
1B/NO_X	Gas	7E	TEI Model 42CHL	42CHL-62888-337
1B/CO_2	Gas	3A	CAI ZRH 1	N3G2200T
1B/O_2	Gas	3A	Thermox	C114306
1B/CO	Gas	10	TEI Model 48C	48C-68844-361

All reference method analyzers used meet or exceed applicable performance specifications detailed in the appropriate method.

Gas samples were continuously extracted from the stack by a gas sample probe. Samples were then transported to a gas sample conditioner via a heated sample line operating at 250°F or above. The gas sample conditioner lowers the dew point of the sample gas to approximately 5°C through minimum interference heat exchangers. The dry, cool sample is then sent to the gas analyzers, located in the environmentally controlled test trailer for analysis by the reference method analyzers.

Instrument outputs were recorded continuously with a Windows compatible personal computer, compiled into 15 second averages, and stored in a database for future reference.

Instrument ranges and calibration gases were chosen in accordance with each pollutant's applicable EPA method. Instrument ranges and calibration gases used are shown in Table 4:

Table 4: Reference Method Instrument Ranges and Calibration Gases
Progress Energy Florida
Hines Energy Complex
Units 1A and 1B

Pollutant	Test Location	Instrument Span	Calibration Gases[a]
NOx	1A and 1B RATA	20 ppm	0.0 ppm NO 8.1 ppm NO 16.1 ppm NO
CO_2	1A and 1B RATA	20%	0.0 % CO_2 10.9 % CO_2 17.6 % CO_2
O_2	1A and 1B Compliance	25 %	0.0 % O_2 12.9 % O_2 21.0 % O_2
CO	1A and 1B Compliance	50 ppm	0.0 ppm CO 12.3 ppm CO 23.6 ppm CO 46.1 ppm CO

[a] Concentrations of NO, CO, CO_2, and O_2 are in a balance of purified nitrogen (N_2). All analyzers were zeroed with ultra high purity N_2. All calibration gases have been certified to NIST traceable standards.

Calibration gas Certificates of Analysis can be found in Appendix C.

4.1.1 Sampling Location/Traverse Points/Test Run Duration

Units 1A and 1B exhaust stack inner diameters, at the sample locations, are 19 feet (228"). The emissions sampling location is 37.5 feet downstream from the nearest flow disturbance, and 10 feet upstream from the stack exhaust. A diagram of the sample location can be viewed in Appendix D.

4.1.1.1 Stratification Test

Gaseous stratification tests were completed on Units 1A and 1B on December 7, 2004 and December 8, 2005 respectively, in accordance with 40CFR, Part 75, Appendix A, Section 6.5.6.1.

Stratification test results are located in Appendix E.

4.1.1.2 Reference Measurement Point

Units 1A and 1B passed the stratification test, therefore, a single reference method measurement point was used for the duration of the test program, located no less than 1.0 meter from the stack wall along one of the measurement lines used in the stratification test in accordance with 40CFR, Part 75, Appendix A, Section 6.5.6(b)(4).

4.1.1.3 Test Run Durations

Units 1A and 1B PNG compliance and CEMS RATA test runs were conducted simultaneously. The RATA runs on Units 1A and 1B were 21 minutes. Each compliance test run is compiled from three consecutive RATA runs. Compliance runs were a total of 63 minutes in duration.

4.1.2 Quality Assurance/Quality Control Procedures

All sampling, analytical, and Quality Assurance/Quality Control (QA/QC) procedures outlined in the EPA methods were followed. All test equipment was calibrated before or during use in the field. Interference checks, response time checks, and NO_2 to NO converter checks were performed on each instrumental analyzer, as applicable, before field use. In the field, each analyzer and the entire instrument measurement system was checked for system bias before and following each test run using the appropriate calibration gases listed in Table 4.

Appendix E contains the QA/QC checks.

4.2 Determination of Opacity

USEPA Method 9 was utilized to determine opacity emissions.

Opacity observations were performed by a FDEP certified visual emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One 30 minute opacity run was performed on each unit, during each compliance test, as required in permit condition A.14 while the units were operating at maximum capacity.

Opacity field data and the observers VE certificate can be viewed in Appendix H.

4.3 Fuel Analysis

The heating value of natural gas was calculated based upon the gas components as analyzed by the gas provider's gas chromatographs. Sulfur content of the PNG was provided by PEF's gas provider as well.

Fuel analysis reports and sulfur calculations are located in Appendix I.

5.0 Test Results

The test program results are summarized in Tables 5 and 6, and are discussed below. Summaries of the compliance test results for NO_X, CO, and SO_2, Supporting RM field data, fuel analysis reports, and calculated values are presented in Appendix F through H.

5.1 Unit 1A

5.1.1 Nitrogen Oxides (NO_X)

NO_X compliance for Unit 1A is continuously determined using the CEMS. The difference between Unit 1A's NOx-diluent CEMS readings and the RM readings over the nine test runs was 0.002 lbs/mmBtu, passing the RATA alternate annual performance specification of 0.015 lbs/mmBtu difference.

5.1.2 Carbon Monoxide (CO)

During the Unit 1A gas compliance test, CO mass emissions averaged 1.69 lbs/hr over the three test runs, passing the 77.0 lbs/hr emission limitation. During the Unit 1A gas compliance test, CO emissions for the three test runs averaged 0.5 ppmvd.

5.1.3 Visual Emissions

The highest opacity emissions observed in any six-minute average on Unit 1A during the 30 minute PNG test run was 0.0%, passing the 10% emission.

5.1.4 Sulfur Dioxide (SO_2)

The sulfur content of the gas burned during the Unit 1A compliance test was 0.691 grains/100dscf, below the 1 grain/100 dscf maximum limitation.

Table 5: Unit 1A Compliance Summary
Progress Energy Florida
Hines Energy Complex

Unit	Parameter	Measured	Limitation	Compliance Status (Pass/Fail)
1A	Nitrogen Oxides (NO_X)	0.002 lbs/mmBtu difference	CEMS RATA ≤10% or < .020 lb/mmBtu difference	Pass
1A	Carbon Monoxide (CO)	1.69 lbs/hr PNG; 0.5 ppmvd	77 lbs/hr for PNG 25 ppmvd	Pass
1A	Visual Emissions	0.0% on PNG	≤10% for PNG	Pass
1A	PNG Sulfur Content	0.691 gr./100 dscf	≤1.0 gr./100 dscf	Pass

5.2 Unit 1B

5.2.1 Nitrogen Oxides (NO_X)

NO_X compliance for Unit 1B is continuously determined using the CEMS. Unit 1B's CEMS passed the RATA with an average difference of 0.003 lbs/mmBtu, below the alternate annual performance specification of 0.015 lbs/mmBtu limitation.

5.2.2 Carbon Monoxide (CO)

During the Unit 1B gas compliance test, CO mass emissions averaged 1.33 lbs/hr over the three test runs, passing the 77.0 lbs/hr emission limitation. During the Unit 1B gas compliance test, CO emissions for the three test runs averaged 0.3 ppmvd.

5.2.3 Visual Emissions

The highest opacity emissions observed in any six-minute average on Unit 1B during the one hour PNG test run was 0.0%, passing the 10% emission limitation.

5.2.4 Sulfur Dioxide (SO_2)

The sulfur content of the gas burned during the Unit 1B compliance test was 0.691 grains/100dscf, below the 1 grain/100 dscf maximum limitation.

Table 6: Unit 1B Compliance Summary
Progress Energy Florida
Hines Energy Complex

Unit	Parameter	Measured	Limitation	Compliance Status (Pass/Fail)
1B	Nitrogen Oxides (NO_x)	0.003 lb/mmBtu	CEMS RATA ≤10% or < .020 lb/mmBtu difference	Pass
1B	Carbon Monoxide (CO)	1.33 lbs/hr, 0.3 ppmvd	77 lbs/hr, 25 ppmvd	Pass
1B	Visual Emissions	0.0% on PNG	≤10% for PNG	Pass
1B	PNG Sulfur Content	0.691 gr./100 dscf	≤1.0 gr./100 dscf	Pass

ATTACHMENT PEF-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT PEF-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

EMISSION UNIT ID: 001, 002, 014, 015, 016, AND 017

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	- NSPS Subpart GG
62-204.800(7)(c) (State Only)	- NSPS authority
62-204.800(7)(d)(State Only)	- NSPS General Provisions
62-204.800(12) (State Only)	- Acid Rain Program
62-204.800(13) (State Only)	- Allowances
62-204.800(14) (State Only)	- Acid Rain Program Monitoring
62-204.800(16) (State Only)	- Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	- Circumvention; EUs with control device
62-210.700(1)	- Excess Emissions;
62-210.700(4)	- Excess Emissions; poor maintenance
62-210.700(6)	- Excess Emissions; notification

Acid Rain:

62-214.300	- All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	- All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	- Compliance Options (if 214.430)
62-214.340	- Exemptions (new units, retired units)
62-214.350(2);(3);(6)	- All Acid Rain Units (Certification)
62-214.370	- All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	- All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	- CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	- All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	- All Units (Operating Rate; other than CTs;no CT)
62-297.310(3)	- All Units (Calculation of Emission)
62-297.310(4)(a)	- All Units (Applicable Test Procedures;Sampling time)
62-297.310(4)(b)	- All Units (Sample Volume)
62-297.310(4)(c)	- All Units (Required Flow Rate Range-PM/H2SO4/F)
62-297.310(4)(d)	- All Units (Calibration)
62-297.310(4)(e)	- All Units (EPA Method 5-only)
62-297.310(5)	- All Units (Determination of Process Variables)
62-297.310(6)(a)	- All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	- All Units (Sampling Ports)
62-297.310(6)(d)	- All Units (Work Platforms)
62-297.310(6)(e)	- All Units (Access)

62-297.310(6)(f)	- All Units (Electrical Power)
62-297.310(6)(g)	- All Units (Equipment Support)
62-297.310(7)(a)1.	- Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	- FFSG excess emissions
62-297.310(7)(a)3.	- Permit Renewal Test Required
62-297.310(7)(a)4.a	- Annual Test
62-297.310(7)(a)5.	- PM exemption if <400 hrs/yr
62-297.310(7)(a)6.	- PM FFSG semi annual test required if >200 hrs/yr
62-297.310(7)(a)7.	- PM quarterly monitoring if >100 hrs/yr
62-297.310(7)(a)9.	- FDEP Notification - 15 days
62-297.310(7)(c)	- Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	- Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	- NOx for Electric Utility CTs
40 CFR 60.332(a)(3)	- NOx for Electric Utility CTs
40 CFR 60.333	- SO2 limits
40 CFR 60.334	- Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	- Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	- Notification of Construction
40 CFR 60.7(a)(2)	- Notification of Initial Start-Up
40 CFR 60.7(a)(3)	- Notification of Actual Start-Up
40 CFR 60.7(a)(4)	- Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	- Notification of CEM Demonstration
40 CFR 60.7(b)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	- Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	- Notification and Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	- Performance Test Requirements
40 CFR 60.8(b)	- Performance Test Notification
40 CFR 60.8(c)	- Performance Tests (representative conditions)
40 CFR 60.8(e)	- Provide Stack Sampling Facilities
40 CFR 60.8(f)	- Test Runs
40 CFR 60.11(a)	- Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	- Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	- Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	- Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	- Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	- Circumvention
40 CFR 60.13(a)	- Monitoring (Appendix B; Appendix F)
40 CFR 60.13(c)	- Monitoring (Opacity COMS)
40 CFR 60.13(d)(1)	- Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(d)(2)	- Monitoring (COMS; span, system check)
40 CFR 60.13(e)	- Monitoring (frequency of operation)

40 CFR 60.13(f)	- Monitoring (frequency of operation)
40 CFR 60.13(h)	- Monitoring (COMS; data requirements)
Acid Rain-Permits:	
40 CFR 72.9(a)	- Permit Requirements
40 CFR 72.9(b)	- Monitoring Requirements
40 CFR 72.9(c)(1)	- SO2 Allowances-hold allowances
40 CFR 72.9(c)(2)	- SO2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	- SO2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	- SO2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	- SO2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	- NOx Requirements
40 CFR 72.9(e)	- Excess Emission Requirements
40 CFR 72.9(f)	- Recordkeeping and Reporting
40 CFR 72.9(g)	- Liability
40 CFR 72.20(a)	- Designated Representative; required
40 CFR 72.20(b)	- Designated Representative; legally binding
40 CFR 72.20(c)	- Designated Representative; certification requirements
40 CFR 72.21	- Submissions
40 CFR 72.22	- Alternate Designated Representative
40 CFR 72.23	- Changing representatives; owners
40 CFR 72.24	- Certificate of representation
40 CFR 72.30(a)	- Requirements to Apply (operate)
40 CFR 72.30(b)(2)	- Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	- Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	- Requirements to Apply (submittal requirements)
40 CFR 72.31	- Information Requirements; Acid Rain Applications
40 CFR 72.32	- Permit Application Shield
40 CFR 72.33(b)	- Dispatch System ID;unit/system ID
40 CFR 72.33(c)	- Dispatch System ID;ID requirements
40 CFR 72.33(d)	- Dispatch System ID;ID change
40 CFR 72.40(a)	- General; compliance plan
40 CFR 72.40(b)	- General; multi-unit compliance options
40 CFR 72.40(c)	- General; conditional approval
40 CFR 72.40(d)	- General; termination of compliance options
40 CFR 72.51	- Permit Shield
40 CFR 72.90	- Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	- Authorized account representative
40 CFR 73.35(c)(1)	- Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	- Compliance Dates;
40 CFR 75.5	- Prohibitions
40 CFR 75.10(a)(1)	- Primary Measurement; SO2;
40 CFR 75.10(a)(2)	- Primary Measurement; NOx;
40 CFR 75.10(a)(3)(iii)	- Primary Measurement; CO2; O2 monitor
40 CFR 75.10(b)	- Primary Measurement; Performance Requirements
40 CFR 75.10(c)	- Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	- Primary Measurement; Optional Backup Monitor

40 CFR 75.10(f)	- Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	- Primary Measurement; Minimum Recording
40 CFR 75.11(d)	- SO2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	- SO2 Monitoring; Gaseous firing
40 CFR 75.12(a)	- NOx Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	- NOx Monitoring; Determination of NOx emission rate; Appendix F
40 CFR 75.13(b)	- CO2 Monitoring; Appendix G
40 CFR 75.13(c)	- CO2 Monitoring; Appendix F
40 CFR 75.14(c)	- Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	- Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	- Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	- Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	- Recertification Backup/portable monitor
40 CFR 75.20(f)	- Alternate Monitoring system
40 CFR 75.21(a)	- QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	- QA/QC; Calibration Gases
40 CFR 75.21(d)	- QA/QC; Notification of RATA
40 CFR 75.21(e)	- QA/QC; Audits
40 CFR 75.21(f)	- QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	- Reference Methods
40 CFR 75.24	- Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	- General Missing Data Procedures; NOx
40 CFR 75.30(a)(4)	- General Missing Data Procedures; SO2
40 CFR 75.30(b)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	- General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	- General Missing Data Procedures; SO2 (optional before 1/1/97)
40 CFR 75.30(e)	- General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	- Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	- Monitoring Data Availability for Missing Data
40 CFR 75.33	- Standard Missing Data Procedures
40 CFR 75.36	- Missing Data for Heat Input
40 CFR 75.40	- Alternate Monitoring Systems-General
40 CFR 75.41	- Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	- Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	- Alternate Monitoring Systems-Accessability Criteria
40 CFR 75.44	- Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	- Alternate Monitoring Systems-Daily QA
40 CFR 75.46	- Alternate Monitoring Systems-Missing data
40 CFR 75.47	- Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	- Alternate Monitoring Systems-Petition
40 CFR 75.53	- Monitoring Plan ; revisions
40 CFR 75.54(a)	- Recordkeeping-general
40 CFR 75.54(b)	- Recordkeeping-operating parameter
40 CFR 75.54(c)	- Recordkeeping-SO2
40 CFR 75.54(d)	- Recordkeeping-NOx
40 CFR 75.54(e)	- Recordkeeping-CO2
40 CFR 75.54(f)	- Recordkeeping-Opacity
40 CFR 75.55(c)	- General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	- General Recordkeeping (Specific Situations)
40 CFR 75.56	- Certification; QA/QC Provisions

40 CFR 75.60	- Reporting Requirements-General
40 CFR 75.61	- Reporting Requirements-Notification cert/recertification
40 CFR 75.62	- Reporting Requirements-Monitoring Plan
40 CFR 75.63	- Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	- Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	- Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	- Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	- Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	- Petitions to the Administrator (if required)
Appendix A-1	- Installation and Measurement Locations
Appendix A-2.	- Equipment Specifications
Appendix A-3.	- Performance Specifications
Appendix A-4.	- Data Handling and Acquisition Systems
Appendix A-5.	- Calibration Gases
Appendix A-6.	- Certification Tests and Procedures
Appendix A-7.	- Calculations
Appendix B	- QA/QC Procedures
Appendix C-1.	- Missing Data; SO2/NOx for controlled sources
Appendix C-2.	- Missing Data; Load-Based Procedure; NOx & flow
Appendix D	- Optional SO2; Oil-/gas-fired units
Appendix F	- Conversion Procedures
Appendix H	- Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

40 CFR 77.3	- Offset Plans (future)
40 CFR 77.5(b)	- Deductions of Allowances (future)
40 CFR 77.6	- Excess Emissions Penalties (SO2 and NOx;future)

ATTACHMENT PEF-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT PEF-EU1-IV3
ALTERNATIVE METHODS OF OPERATION

Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternative fuel.

Fuel usage while burning natural gas at the site shall not contain more than 1.0 grains of Sulfur per 100 standard cubic feet of natural gas. Fuel usage of both emission units while burning fuel oil at the site, shall not exceed 13,762,806 gallons (LHV) per year during any consecutive 12 month period.

Fuel Oil Operation

The maximum heat input rate, based on the higher heating value (HHV) of No. 2 fuel oil at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 2,020 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil.

The amount of fuel oil burned at this site (in BTU's) will not exceed the amount of natural gas burned at this site (in BTU's) during any consecutive 12-month period **[Rule 62-210.200, F.A.C. (BACT)]**.

Natural Gas Operation

The maximum heat input rate, based on the higher heating value (HHV) of natural gas at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 1,915 MMBtu/hr when firing natural gas.

Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, fuels and evaporative cooling.

ATTACHMENT PEF-EU1-IV5

ACID RAIN PART APPLICATION

Back Print

Reports and Queries

Certificate of Representation

03/30/2006

Facility Information

Facility ID (ORISPL): 7302 **Facility Name:** Hines Energy Complex **State:** FL

Facility Detail (Mini Detail)

Representative Information

Name: Brenda Brickhouse
Company: Progress Energy Corporation
Title: Director, Environmental Services
Address: P.O. Box 1551
PEB7
City: Raleigh **State:** NC **Zip:** 27602-1551
Phone: (727) 562-3855 **Fax:** (919) 546-7558
Email: brenda.brickhouse@pgnmail.com

Name: J. Michael Kennedy
Company: Progress Energy Corporation
Title: Principal Environmental Specialist
Address: P O Box 14042
MAC - CX1B
City: St. Petersburg **State:** FL **Zip:** 33733
Phone: (727) 820-5567 **Fax:** (727) 820-5229
Email: j-michael.kennedy@pgnmail.com

People Detail Layout (Multiple)

Current Representatives

Unit ID	Program	Unit Classification	Primary Representative, Effective Date	Alternate Representative, Effective Date	Primary Representative, End Date	Alternate Representative End Date
1A	ARP	Phase 2 Operating	J. Michael Kennedy,	Brenda Brickhouse, 02/25/2005		

			10/27/2000			
1B	ARP	Phase 2 Operating	J. Michael Kennedy, 10/27/2000	Brenda Brickhouse, 02/25/2005		
2A	ARP	Phase 2 Operating	J. Michael Kennedy, 05/31/2002	Brenda Brickhouse, 02/25/2005		
2B	ARP	Phase 2 Operating	J. Michael Kennedy, 05/31/2002	Brenda Brickhouse, 02/25/2005		
3A	ARP	Phase 2 Operating	J. Michael Kennedy, 04/14/2003	Brenda Brickhouse, 02/25/2005		
3B	ARP	Phase 2 Operating	J. Michael Kennedy, 04/14/2003	Brenda Brickhouse, 02/25/2005		

Basic Table Layout

Current Owners and Operators

Unit ID	Owner/Operator Company Name	Type	Effective Date	End Date
1A	Florida Power Corporation	Owner/Operator	03/07/2003	
1B	Florida Power Corporation	Owner/Operator	03/07/2003	
2A	Florida Power Corporation	Owner/Operator	03/07/2003	
2B	Florida Power Corporation	Owner/Operator	03/07/2003	
3A	Florida Power Corporation	Owner/Operator	04/14/2003	
3B	Florida Power Corporation	Owner/Operator	04/14/2003	

Basic Table Layout

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [2] of [5]
Power Block 2

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Power Block 2 consists of two identical Westinghouse 501FD combined cycle combustion turbines firing natural gas with distillate oil back-up.

3. Emissions Unit Identification Number: **014, 015**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Generator nameplate rating given is per CT. Total Power Block 2 generating capacity of approximately 530 MW, including two CTs at 170 MW each and 190 MW steam turbine-electrical generator.

EMISSIONS UNIT INFORMATION

Section [2] of [5]
Power Block 2

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Dry Low NO_x combustion - natural gas firing.

   Selective Catalytic Reduction (SCR) – natural gas firing/distillate oil firing.

   Water Injection – distillate oil firing.

2. Control Device or Method Code(s): **025, 065, 028**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **2,048** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule:	
24hours/day	**7**days/week
52weeks/year	**8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input is higher heating value (HHV) with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating. Fuel oil firing maximum Heat Input Rate = 2,155 MMBtu/hr (HHV). (Heat Input Rates as per Title V permit revision 1050234-012-AV.)**	

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT2A, CT2B**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each combustion turbine exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190°F**	9. Actual Volumetric Flow Rate: **1,009,487** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet.**		

EMISSIONS UNIT INFORMATION
Section [2] of [5]
Power Block 2

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.99**	5. Maximum Annual Rate: **17,418**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**
10. Segment Comment: **Per CT. Based on 1,030 BTU/CF (HHV); maximum hourly and annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **15.26**	5. Maximum Annual Rate: **19,703**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment: **Per CT. BTU based on HHV of 141.2 MMBtu/1,000 gallons. Aggregate fuel usage of 19,703,000 gallons per year for Power Block 2. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.**		

EMISSIONS UNIT INFORMATION
Section [2] of [5]
Power Block 2

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	065	EL
CO			EL
VOC			EL
SAM			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **64.8** lb/hour **52.7** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-296A, Permit No. 1050234-012-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **7.3** lb/hour **32** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Permit No. 1050234-012-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **23.3** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A, Permit No. 1050234-012-AV, 720 hr/yr/CT**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **105.6** lb/hour **60.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-296A. Permit No. 1050234-012-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas – 1 grain S/100 scf**	4. Equivalent Allowable Emissions: **5.6** lb/hour **24.5** tons/year
5. Method of Compliance: **Fuel Sampling – Vendor or Permittee.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Permit No. 1050234-012-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **38.0** tons/year
5. Method of Compliance: **Fuel Sampling – Vendor or Permittee.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A, Permit No. 1050234-012-AV. 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **99.7** lb/hour **144.4** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-296A. Permit No. 1050234-012-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **3.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **27** lb/hour **118.3** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Permit No. 1050234-012-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **12 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **99.7** lb/hour **35.9** tons/year
5. Method of Compliance: **CEM Part 75; 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A, Permit No. 1050234-012-AV, 720 hr/yr/CT**	

Allowable Emissions Allowable Emissions ____ of ____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **119.5** lb/hour **359.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-296. Permit No. 1050234-012-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing; TPY with 8,040 hr/yr-gas and 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **16 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **78.7** lb/hour **345** tons/year
5. Method of Compliance: **CEM 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Permit No. 1050234-012-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **30 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **119.5** lb/hour **43** tons/year
5. Method of Compliance: **CEM 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A, Permit No. 1050234-012-AV, 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **23.5** lb/hour **28.6** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-296A. Permit No. 1050234-012-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas (100% and 60% loads); equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **5** lb/hour **21.9** tons/year
5. Method of Compliance: **EPA Method 25A. Initial test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Permit No. 1050234-012-AV**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **23.5** lb/hour **8.46** tons/year
5. Method of Compliance: **EPA Method 25A. Initial test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A, Permit No. 1050234-012-AV, 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **< 11** lb/hour **< 6.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Estimated < 10% of SO2 emissions.** Reference: **PSD-FL-296A.**	7. Emissions Method Code: **0**
8. Calculation of Emissions: **Estimated < 10% of SO2 emissions.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil. Emissions are estimated.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas – 1 grain/100 scf**	4. Equivalent Allowable Emissions: **< 0.60** lb/hour **< 2.5** tons/year
5. Method of Compliance: **See SO2 Method of Compliance.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-296A. Emissions estimated < 10% of SO2 emissions.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **< 11** lb/hour **< 3.8** tons/year
5. Method of Compliance: **See SO2 Method of Compliance.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-296A. Emissions estimated < 10% of SO2 emissions.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Gas and Oil Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **20** % Maximum Period of Excess Opacity Allowed: **See Comment** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Title V Permit 1050234-008-AV Condition E.6. 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. and PSD-FL-296A]**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **O_2**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **Servomex (CT2A, CT2B)** Model Number: **1440 (CT2A, CT2B)** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date: **Dec 2003**
7. Continuous Monitor Comment: **Serial No. for CT2A: 1440/2756. Serial No. for CT2B: 1440/2755** **See NO_x.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: **TECO (CT2A, CT2B)** Model Number: **42CHL (CT2A, CT2B)** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT2A: 42CHL-74691-377 Serial No. for CT2B: 42CHL-74692-377** **Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_x CEM in lieu of WTF monitoring. 40 CFR 75. PSD-FL-296A. Permit No. 1050234-012-AV**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement: ☐ Rule ☒ Other	
4. Monitor Information... Manufacturer: **TECO (CT2A, CT2B)** Model Number: **48C CO (CT2A, CT2B)** Serial Number: **See Comment**	
5. Installation Date:	6. Performance Specification Test Date: **Dec 2003**
7. Continuous Monitor Comment: **Serial No. for CT2A: 48C-73424-373. Serial No. for CT2B: 48C-73426-373.** **Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

Continuous Monitoring System: Continuous Monitor ___ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☒ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date ____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I2** ☐ Previously Submitted, Date ____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I3** ☐ Previously Submitted, Date ____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date ____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date ____
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☒ Attached, Document ID: **PEF-EU2-I6**
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   ☐ Previously Submitted, Date: ____
   Test Date(s)/Pollutant(s) Tested: ____
   ____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: ____
   ☐ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: **PEF-EU1-IV1** ☐ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: **PEF-EU2-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID: **PEF-EU1-IV5**
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT PEF-EU2-I6

COMPLIANCE DEMONSTRATION REPORTS

Air Emissions Compliance Test Report

Progress Energy Florida
Hines Energy Complex, Units 2A and 2B
Bartow, Florida

C.E.M. Solutions Project No. 2455

Testing Completed: September 2005

Client Purchase Order Number: 49782
C.E.M. Solutions, Inc Report Number: 20-2455-02-001

C.E.M. Solutions, Inc.
7990 W. Gulf to Lake Hwy.
Crystal River, Florida 34429
Phone: 352-564-0441

Project Background

Name of Source Owner:	Progress Energy Florida
Address of Owner:	One Power Plaza 263 13th Avenue South St. Petersburg, Florida 33701
Source Identification:	Oris Code: 7302 Facility ID: 1050234 Emissions Unit: -014, -015
Location of Source:	Polk County, Florida
Type of Operation:	SIC Code: 4911
Tests Performed:	Method 3A – Determination of Oxygen and Carbon Dioxide Method 7E – Determination of Nitrogen Oxides Method 9 – Visual Determination of Opacity Method 10 – Determination of Carbon Monoxide Method 19 – Determination of Nitrogen Oxide Emissions Rates ASTM D-240 – Fuel Analysis (by others) ASTM D-1552 – Sulfur in Petroleum Products (by others) CTM 27 – Analysis of Ammonia in Stationary Sources
Test Supervisor:	Mr. Jeremy A. Johnson
Date(s) Tests Conducted:	2A: September 28, 2005 2B: September 29, 2005
Site Test Coordinator:	Mr. James T. Long
State Regulatory Observers:	No Observers Present

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Appendices

1.0 Introduction

Progress Energy, Florida (PEF) retained C.E.M. Solutions, Inc. to perform source emissions testing on Units 2A and 2B stationary combustion turbines located at its Hines Energy Complex in Bartow, Florida.

The test program was conducted in order to evaluate the compliance status of Units 2A and 2B exhaust while firing Pipeline Natural Gas (PNG), in respect to the United States Environmental Protection Agency (USEPA) Standards of Performance for Stationary Turbines (Title 40 of the Code of Federal Regulations, Part 60, Subpart GG) and the Florida Department of Environmental Protection's (FDEP's) permit number 1050234-012-AV. The test program and results are presented and discussed in this report.

James T. Long of Progress Energy's Environmental Services Section coordinated plant operations throughout the test program. All testing was conducted in accordance with test methods promulgated by the USEPA.

2.0 Facility Description

The Hines Units 2A and 2B are Westinghouse 501FD Combustion Turbine models having a nominal generating capacity of 170 MW and are all capable of firing natural gas or distillate oil.

2.1 Process Equipment

Units 2A and 2B each have a maximum heat input rating, at an ambient temperature of 59°F, that shall not exceed 1,915 million Btu per hour (mmBtu/hr) when firing natural gas and 2,020 on distillate oil. Heat inputs are based on the High Heating Value (HHV) for each fuel.

Control measures and equipment consists of dry low NO_x burners and Selective Catalytic Reduction. Each combustion turbine incorporates an unfired heat recovery steam generator. Emissions are exhausted through separate 110 ft. stacks, each having an inner diameter of 19 ft.

2.2 Regulatory Requirements

PEF is required to conduct annual emissions tests for the following pollutants while operating at 90-100 percent of the heat input curve. Emission testing was conducted to determine the compliance status of the following pollutants:

- NO_X (demonstrated by CEMS Relative Accuracy Test Audit)
- SO_2 in % S by weight of fuel and pounds per hour
- CO (demonstrated by CEMS Relative Accuracy Test Audit)
- Opacity in percent
- Ammonia Slip in ppmvd @ 15% O_2

Table 1 summarizes the applicable emissions limits for Units 2A and 2B.

Table 1: Summary of Emissions Limits
Progress Energy Florida
Hines Energy Complex
Units 2A and 2B

Pollutant	Emission Limit	Permit Condition
Visual Emission	≤10% for gas	E.4.e
CO	≤10% Error on CEMS RATA, or ± 5 ppm	E.4.a
SO_2	1 grain/100 dscf for gas	E.4.f
NH_3	< 5 ppm @ 15% O_2	E.4.d
NO_X	≤10% Error on CEMS RATA, Or ± 0.020 lbs/mmBtu	E.4.b

3.0 Test Program/Operating Conditions

Emissions tests were completed on Units 2A and 2B at the Hines Energy Complex to determine the compliance status of the fuel turbines on September 28, 2005 and September 29, 2005 respectively.

Opacity compliance and ammonia slip testing was performed concurrently with 40CFR, Part 60 and 75 Relative Accuracy Testing conducted on Units 2A and 2B CEMS NO_X and CO analyzers, at high load, while firing PNG.

Units 2A and 2B SO_2 compliance was calculated from fuel analysis on fuel used during the compliance test.

Turbine operating data was collected and provided by facility personnel during the entire test program. Data provided include, but was not limited to, the following:

- Unit Generation (MW)
- Combustor inlet air temperature (°F)
- Fuel flow rate

Table 2 summarizes the heat input for each unit during the compliance tests.

Table 2: Summary of Heat Inputs
Progress Energy Florida
Hines Energy Complex
Units 2A and 2B

Unit	Fuel	Heat Input (mmBtu/hr)	Inlet Temperature (°F)	Maximum Heat Input @ Temp	Percent of Maximum Heat Input
Unit 2A	Gas	1746.8	83.65	1940	90.0%
Unit 2B	Gas	1716.4	82.48	1950	88.0%

Units 2A and 2B operating data, heat input curves, and heat input calculations can be viewed in Appendix A.

4.0 Test Methods

All testing was performed in accordance with methods approved by the USEPA and FDEP. The following discusses the methods, as well as quality assurance and sample handling procedures.

4.1 Instrument Analyzer Procedures

Units 2A and 2B CO reference method (RM) data was determined using instrument analyzer procedures. EPA Method 10 was used for the Relative Accuracy Test Audit (RATA) on the Units 2A and 2B CEMS CO analyzers. In addition, diluent gas concentrations of oxygen (O_2) were also measured via instrumental methods.

NO_X RM data was determined using instrument analyzer procedures as well. EPA Method 7E was used for the Relative Accuracy Test Audit (RATA) on the Units 2A and 2B CEMS NO_x analyzers. O_2 data was also used to calculate NO_X pollutant emissions pounds per million Btu.

Mathematical equations used to determine calculated emissions standards are located in Appendix B.

RATA results and supporting RM and CEMS data can be viewed in Appendix F. Table 3 summarizes the EPA methods and instrumentation:

Table 3: Summary of EPA Instrument Reference Methods
Progress Energy Florida
Hines Energy Complex
Units 2A and 2B

Unit/Pollutant	Fuel	EPA Method	Instrument	Serial Number
2A/NO_X	Gas	7E	TEI Model 42CHL	42CHL-74122-375
2A/ CO_2	Gas	3A	Servomex	1415D/3379
2A/O_2	Gas	3A	Servomex	1420D/3379
2A/CO	Gas	10	TEI Model 48C	48C-74094-375
2B/NO_X	Gas	7E	TEI Model 42CHL	42CHL-74122-375
2B/CO_2	Gas	3A	Servomex	1415D/3379
2B/O_2	Gas	3A	Servomex	1420D/3379
2B/CO	Gas	10	TEI Model 48C	48C-74094-375

All reference method analyzers used meet or exceed applicable performance specifications detailed in the appropriate method.

Gas samples were continuously extracted from the stack by a gas sample probe. Samples were then transported to a gas sample conditioner via a heated sample line operating at 250°F or above. The gas sample conditioner lowers the dew point of the sample gas to approximately 5°C through minimum interference heat exchangers. The dry, cool sample is then sent to the gas analyzers, located in the environmentally controlled test trailer for analysis by the reference method analyzers.

Instrument outputs were recorded continuously with a Windows compatible personal computer, compiled into 15 second averages, and stored in a database for future reference.

Instrument ranges and calibration gases were chosen in accordance with each pollutant's applicable EPA method. Instrument ranges and calibration gases used are shown in Table 4:

Table 4: Reference Method Instrument Ranges and Calibration Gases
Progress Energy Florida
Hines Energy Complex
Units 2A and 2B

Pollutant	Test Location	Instrument Span	Calibration Gases[a]
NO_X	2A and 2B RATA	10 ppm	0.0 ppm NO 5.3 ppm NO 8.1 ppm NO
CO_2	2A and 2B RATA	20%	0.0 % CO_2 10.9 % CO_2 17.6 % CO_2
O_2	2A and 2B Compliance	25 %	0.0 % O_2 12.9 % O_2 21.0 % O_2
CO	2A and 2B Compliance	50 ppm	0.0 ppm CO 12.3 ppm CO 23.6 ppm CO 46.1 ppm CO

[a] Concentrations of NO, CO, CO_2, and O_2 are in a balance of purified nitrogen (N_2). All analyzers were zeroed with ultra high purity N_2. All calibration gases have been certified to NIST traceable standards.

Calibration gas Certificates of Analysis can be found in Appendix C.

4.1.1 Sampling Location/Traverse Points/Test Run Duration

Units 2A and 2B's exhaust stack inner diameters, at the sample locations, are 19 feet (228"). The emissions sampling location is 37.5 feet downstream from the nearest flow disturbance, and 10 feet upstream from the stack exhaust. A diagram of the sample locations can be viewed in Appendix D.

4.1.1.1 Reference Measurement Point

Three reference method measurement points were used for the duration of the RATA test program in accordance with 40CFR, Part 75, Appendix A, Section 6.5.6(b)(2)on both PB 2A and 2B. The points were located at 4.4% (10.0"), 14.6% (33.25"), and 29.6% (67.5") of the inner stack diameter. The sample probe was located at each sample point for 7 minutes.

4.1.1.2 Test Run Durations

The RATA runs on Units 2A and 2B were 21 minutes in duration. The Ammonia Slip Test runs were 60 minutes in duration.

4.1.2 Quality Assurance/Quality Control Procedures

All sampling, analytical, and Quality Assurance/Quality Control (QA/QC) procedures outlined in the EPA methods were followed. All test equipment was calibrated before or during use in the field. Interference checks, response time checks, and NO_2 to NO converter checks were performed on each instrumental analyzer, as applicable, before field use. In the field, each analyzer and the entire instrument measurement system was checked for system bias before and following each test run using the appropriate calibration gases listed in Table 5.

Appendix E contains the QA/QC checks.

4.2 Determination of Opacity

USEPA Method 9 was utilized to determine opacity emissions.

Opacity observations were performed by a FDEP certified visual emissions reader. Readings were taken at 15 second intervals and reduced into six minute averages as required by the applicable EPA standard. One 30 minute opacity run was performed on each unit, during each compliance test, as required in permit condition E.11 while the units were operating at maximum capacity.

Opacity field data and the observers VE certificate can be viewed in Appendix G.

4.3 Fuel Analysis

The heating value of natural gas was calculated based upon the gas components as analyzed by the gas provider's gas chromatographs. Sulfur content of the PNG was provided by PEF's gas provider as well.

Fuel analysis reports and sulfur calculations are located in Appendix H.

4.4 Ammonia Slip Test

Ammonia concentrations were determined using EPA Conditional Test Method 27 (CTM-027).

Stack gas-samples were extracted at a constant rate, less than or equal to 0.75 cubic feet per minute, for a period of 60 minutes. Gas samples were pulled from the stack through a glass nozzle and glass lined probe configured like a USEPA Method 17 sampling train. The gas was then transported, via an unheated Teflon line, to an impinger train. The impinger train consisted of two Greenburg-Smith (G-S) impingers (impingers 1 and 2) and two modified G-S impingers with the tips removed (impingers 3 and 4) all connected in series in an ice bath. Impingers 1, 2 and 3 were charged with 100ml of 0.1N sulfuric acid (H_2SO_4) solution. The fourth impinger was loaded with a pre-weighed amount of silica gel.

The volume of the liquid (catch) in each of the first three impingers was recorded for future use. Each impinger catch was transferred into individual, clean 500-mil HDPE containers. Each container was then labeled and stored on ice for shipment to the laboratory, where the samples were analyzed within 2 weeks after their collection.

An ion chromatograph equipped with a conductivity detector was used for ammonium ion separation and quantitation to analyze the samples. At a minimum, the first two impingers were analyzed for ammonia breakthrough. Analysis of the third impinger is conducted when breakthrough from the first impinger to the second impinger is experienced.

Pre and post impinger weights, field data collection, and lab analysis results are presented in Appendix I.

A single reference method point was used for the Ammonia Slip test. The test point was located at least 1 meter from inside the interior wall of the stack.

4.4.1 Quality Assurance/Quality Control Procedures

The sample train was leak checked prior to and following each test run at or above the highest vacuum recorded during the test run in accordance with the test method.

Prior to conducting each test run, the impinger train was chilled in ice for at least 10 minutes as specified in the test method.

All sample train glassware was cleaned prior to each test run with deionized (DI) water.

Following each test run, the nozzle, probe and Teflon tube were rinsed with DI water and stored in the same storage container as the catch from impinger 1. Impingers 1, 2 and 3 were rinsed with DI water after recovery and stored with the impinger catch from its perspective impinger as well.

For the duration of each run, the sample probe was maintained at a temperature equal to or greater than the observed stack gas temperature and the exit temperature of the impinger train was maintained at less than or equal to 59 °F.

QA/QC forms can be viewed in Appendix E.

5.0 Test Results

The test program results are summarized in Tables 5 and 6, and are discussed below. Summaries of the compliance test results for NO_X, CO, VE, SO_2, and Ammonia Slip, supporting RM field data, fuel analysis reports, and calculated values are presented in Appendix F through I.

5.1 Unit 2A

5.1.1 Nitrogen Oxides (NO_X)

NO_X compliance for Unit 2A is continuously determined using the CEMS. The difference between Unit 2A's NOx-diluent CEMS readings and the RM readings over the nine test runs was 0.002 lbs/mmBtu, passing the RATA alternative annual performance specification of 0.020 lbs/mmBtu difference.

Run 3 of the RATA test was not used in the RATA or the Compliance test due the NO_X analyzer failing the post bias test, at greater than 5% bias.

5.1.2 Carbon Monoxide (CO)

CO compliance for Unit 2A is continuously determined using the CEMS. Unit 2A's CEMS passed the RATA with an average difference of 2.7 ppm, below the 40CFR60, Appendix A, alternative Performance Specification of 5.0 ppm.

5.1.3 Visual Emissions

The highest opacity emissions observed in any six-minute average on Unit 2A during the 30 minute PNG test run was 0.0%, passing the 10% emission.

5.1.4 Sulfur Dioxide (SO_2)

The sulfur content of the gas burned during the Unit 2A compliance test was 0.654 grains/100dscf, below the 1 grain/100 dscf maximum limitation.

5.1.5 Ammonia Slip

The average of the 3 ammonia slip test run on Unit 2A was determined to be 0.1 ppmvd @15% O_2, below the 5.0 ppm limitation.

The average NO_x concentration over the 3 ammonia slip test runs was 3.08 ppm @ 15% O_2.

5.2 Unit 2B

5.2.1 Nitrogen Oxides (NO_X)

NO_X compliance for Unit 2B is continuously determined using the CEMS. Unit 2B's CEMS passed the RATA with an average difference of 0.003 lbs/mmBtu, below the alternative annual performance specification of 0.020 lbs/mmBtu.

5.2.2 Carbon Monoxide (CO)

CO compliance for Unit 2B is continuously determined using the CEMS. Unit 2B's CEMS passed the RATA with an average difference of 1.1 ppm, below the alternative performance specification of 5.0 ppm.

5.2.3 Visual Emissions

The highest opacity emissions observed in any six-minute average on Unit 2B during the one hour PNG test run was 0.0%, passing the 10% emission limitation.

5.2.4 Sulfur Dioxide (SO_2)

The sulfur content of the gas burned during the Unit 2B compliance test was 0.630 grains/100dscf, below the 1 grain/100 dscf maximum limitation.

5.2.5 Ammonia Slip

The average of the 3 ammonia slip test runs on Unit 2B was determined to be 0.0 ppmvd @15% O_2, below the 5.0 ppm limitation.

The average NO_x concentration over the 3 ammonia slip test runs was 3.05 ppm @ 15% O_2.

Table 5: Unit 2A Compliance Summary
Progress Energy Florida
Hines Energy Complex

Unit	Parameter	Measured	Limitation	Compliance Status (Pass/Fail)
2A	Nitrogen Oxides (NO_X)	0.002 lbs/mmBtu difference	CEMS RA ≤ 10% or < .020 lb/mmBtu difference	Pass
2A	Carbon Monoxide (CO)	2.7 ppm difference	CEMS RA ≤ 5.0 ppm difference	Pass
2A	Visual Emissions	0.0% on PNG	≤ 10% for PNG	Pass
2A	PNG Sulfur Content	0.654 gr./100 dscf	≤ 1.0 gr./100 dscf	Pass
2A	Ammonia (NH_3)	0.1 ppm @15% O_2	≤ 5.0 ppmvd @15% O_2	Pass

Table 6: Unit 2B Compliance Summary
Progress Energy Florida
Hines Energy Complex

Unit	Parameter	Measured	Limitation	Compliance Status (Pass/Fail)
2B	Nitrogen Oxides (NO_X)	0.003 lb/mmBtu	CEMS RA ≤ 10% or < .020 lb/mmBtu difference	Pass
2B	Carbon Monoxide (CO)	1.1 ppm difference	CEMS RA ≤ 5.0 ppm difference	Pass
2B	Visual Emissions	0.0% on PNG	≤ 10% for PNG	Pass
2B	PNG Sulfur Content	0.630 gr./100 dscf	≤ 1.0 gr./100 dscf	Pass
2B	Ammonia (NH_3)	0.0 ppm @15% O_2	≤ 5.0 ppmvd @15% O_2	Pass

ATTACHMENT PEF-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT PEF-EU2-IV3
ALTERNATIVE METHODS OF OPERATION

Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternative fuel.

Fuel usage while burning natural gas at the site shall not contain more than 1.0 grains of Sulfur per 100 standard cubic feet of natural gas. Fuel usage of both emission units while burning fuel oil at the site, shall not exceed 19,703,000 gallons (LHV) per year during any consecutive 12 month period.

Fuel Oil Operation

The maximum heat input rate, based on the higher heating value (HHV) of No. 2 fuel oil at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 2,155 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil.

The amount of fuel oil burned at this site (in BTU's) will not exceed the amount of natural gas burned at this site (in BTU's) during any consecutive 12-month period **[Rule 62-210.200, F.A.C. (BACT)]**.

Natural Gas Operation

The maximum heat input rate, based on the higher heating value (HHV) of natural gas at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 2,048 MMBtu/hr when firing natural gas.

Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, fuels and evaporative cooling.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [3] of [5]
Power Block 3

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Power Block 3 consists of two identical Westinghouse 501FD combined cycle combustion turbines firing natural gas with distillate oil back-up.

3. Emissions Unit Identification Number: **016, and 017**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Siemens Westinghouse** Model Number: **501 FD**

10. Generator Nameplate Rating: **170** MW

11. Emissions Unit Comment:
    Generator nameplate rating given is per CT. Total Power Block 3 generating capacity of approximately 530 MW, including two CTs at 170 MW each and 190 MW steam turbine-electrical generator.
    Date of First Fire: 8/11/05
    Date of Commercial Operation: 11/1/05

EMISSIONS UNIT INFORMATION
Section [3] of [5]
Power Block 3

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   Dry Low NO_x combustion - natural gas firing.

   Selective Catalytic Reduction (SCR) – natural gas firing/distillate oil firing.

   Water Injection – distillate oil firing.

2. Control Device or Method Code(s): **025, 065, 028**

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **2,048** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24**hours/day **52**weeks/year	**7**days/week **8,760** hours/year
6. Operating Capacity/Schedule Comment: **Heat input is higher heating value (HHV) with natural gas; heat input at 59°F turbine inlet temperature; MW nominal rating. Fuel oil firing maximum Heat Input Rate = 2,155 MMBtu/hr (HHV). (Heat Input Rate as per Title V permit revision 1050234-012-AV.)**	

EMISSIONS UNIT INFORMATION
Section [3] of [5]
Power Block 3

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **CT3A, CT3B**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each combustion turbine exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **125** feet	7. Exit Diameter: **19** feet
8. Exit Temperature: **190**°F	9. Actual Volumetric Flow Rate: **1,010,664** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Temperature and flow for natural gas at 59°F turbine inlet.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.99**	5. Maximum Annual Rate: **17,418**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,030**
10. Segment Comment: **Per CT, based on 1,030 BTU/CF (HHV), 2,048 MMbtu/hr; maximum hourly and annual at 59°F; turbine inlet temperatures.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Distillate Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Used**	
4. Maximum Hourly Rate: **15.26**	5. Maximum Annual Rate: **19,703**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment: **BTU based on HHV of 141.2 MMBtu/1,000 gallons, 2,155 MMBtu/hr. Aggregate fuel usage of 19,703,000 gallons per year for Power Block 3. Fuel oil consumption is not limited per turbine, and the allowable fuel may be used in a single turbine.**		

EMISSIONS UNIT INFORMATION
Section [3] of [5]
Power Block 3

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_x	026	065	EL
CO			EL
VOC			EL
SAM			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **64.8** lb/hour **57.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **8.5** lb/hour **37** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **64.8** lb/hour **23.3** tons/year
5. Method of Compliance: **EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: 720 hr/yr/CT, Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **105.6** lb/hour **60.5** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.PSD-FL-330.**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas – 1 grain S/100 scf**	4. Equivalent Allowable Emissions: **5.6** lb/hour **24.5** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **105.6** lb/hour **38.0** tons/year
5. Method of Compliance: **Fuel Sampling - Vendor.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330, 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **76.9** lb/hour **99.6** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-330. Permit No. 1050234-013-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2.5 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **17.9**lb/hour **78.4** tons/year
5. Method of Compliance: **CEM; part 75; 24-hour block average**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-330, Permit No. 1050234-013-AC**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **76.9** lb/hour **27.7** tons/year
5. Method of Compliance: **CEM Part 75; 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-330, Permit No. 1050234-013-AC , 720 hr/yr/CT**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **75** lb/hour **211.9** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-330. Permit No. 1050234-013-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: Per CT. **Max lb/hr for oil firing; TPY with 8,040 hr/yr-gas and 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **46** lb/hour **201** tons/year
5. Method of Compliance: **CEM 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-330. Permit No. 1050234-013-AC**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **20 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **75** lb/hour **27** tons/year
5. Method of Compliance: **CEM 24-hour block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-330, Permit No. 1050234-013-AC 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **22** lb/hour **29.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: Reference: **PSD-FL-330. Permit No. 1050234-013-AC**	7. Emissions Method Code: **0**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Per CT. Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas (100% and 60% loads); equivalent of 720 hr/yr/CT-oil.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **2 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **5.3** lb/hour **23.2** tons/year
5. Method of Compliance: **EPA Method 25A. Initial test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Gas firing: PSD-FL-330. Permit No. 1050234-013-AC**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **10 ppmvd at 15% O_2**	4. Equivalent Allowable Emissions: **22** lb/hour **7.9** tons/year
5. Method of Compliance: **EPA Method 25A. Initial test.**	
6. Allowable Emissions Comment (Description of Operating Method): **Per CT. Oil firing: PSD-FL-330, Permit No. 1050234-013-AC, 720 hr/yr/CT.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SAM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **< 11** lb/hour **< 6.1** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **Estimated less than 10% of SO2** Reference: **Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	7. Emissions Method Code: **0**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Max lb/hr for oil firing at 20°F turbine inlet; TPY with 8,040 hr/yr-gas; equivalent of 720 hr/yr/CT-oil. Emissions are estimated.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **Natural Gas – 1 grain/100 scf**	4. Equivalent Allowable Emissions: **< 0.56** lb/hour **< 2.5** tons/year
5. Method of Compliance: **See SO2 Method of Compliance.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas firing: Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330. Emissions are estimated.**	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.05% Sulfur oil**	4. Equivalent Allowable Emissions: **< 11** lb/hour **< 3.8** tons/year
5. Method of Compliance: **See SO2 Method of Compliance.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil firing: Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330. Emissions are estimated.**	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **Gas and Oil Firing**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **20** % Maximum Period of Excess Opacity Allowed: **See Comment** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **Construction Permit No. PSD-FL-330 Condition 12, 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.]**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 1 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **O_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Servomex (CT3A, CT3B)** Model Number: **1440 (CT3A, CT3B)**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT3A: 01440C1STD/2896. Serial No. for CT3B: 01440C1STD/2885** **See NO_x.**	

Continuous Monitoring System: Continuous Monitor 2 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **42C LS**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT3A: 0424708033. Serial No. for CT3B: 0424508178** **Required by 40 CFR 60; Subpart GG; S.60.334; oil firing. Request NO_x CEM in lieu of WTF monitoring. 40 CFR 75. Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor 3 of 3

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **TECO** Model Number: **48CTL**	Serial Number: **See Comment**
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **Serial No. for CT3A: 0415406563. Serial No. for CT3B: 0415406564.** **Project No. 1050234-006-AC (and 1050234-013-AC), PSD-FL-330.**	

Continuous Monitoring System: Continuous Monitor ___ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I2** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I3** ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I4** ☐ Previously Submitted, Date _____
   ☐ Not Applicable

6. Compliance Demonstration Reports/Records
   ☒ Attached, Document ID: **PEF-EU3-I6**
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [3] of [5]
Power Block 3

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☒ Attached, Document ID: **PEF-EU1-IV1** ☐ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☒ Attached, Document ID: **PEF-EU3-IV3** ☐ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☒ Certificate of Representation (EPA Form No. 7610-1)
      ☒ Copy Attached, Document ID: **PEF-EU1-IV5**
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT PEF-EU3-I6

COMPLIANCE DEMONSTRATION REPORTS

Progress Energy

INITIAL CERTIFICATION APPLICATION
40 CFR Part 60 – CO CEMS
Units 3A and 3B

for

Progress Energy – Hines Energy Complex
Bartow, Polk County, Florida

December 2005

Prepared By:

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- Plant CEMS Calibration Gas Certificates of Analysis
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1.0 INTRODUCTION

Progress Energy's Hines Energy Complex – Power Block 3 (Hines PB3) operates two (2) units (Units 3A and 3B) that are subject to the state emissions monitoring and reporting requirements for CO as set forth by the Florida Department of Environmental Protection (FL DEP) in Title 40 of the Code of Federal Regulations (CFR) Part 60[1].

Hines PB3 has installed and certified a CO continuous emissions monitoring system (CEMS) on each of the two affected units to comply with the monitoring, recordkeeping and reporting requirements of the 40 CFR Part 60, Appendix B, Performance Specification (PS) 4 and 4A rule. Each CO CEMS consists of one (1) dual-range (0-50 and 0-5,000 ppm) Thermo Environmental Instruments Model 48C CO analyzer. Each CEMS utilizes a straight-extractive sampling and conditioning system.

This certification application and associated appendices includes the certification tests results for Units 3A and 3B. Unit, stack, and CEMS diagrams are provided in Appendix 2. Table 1-1 summarizes a general CO CEMS description for the units.

Table 1-1. CO CEMS Analyzer Information – Units 3A and 3B

3A	PS-4A	0–50 ppm	Thermo Environmental Instruments, Inc.	48C	0415406563
	PS-4	0–5,000 ppm			
3B	PS-4A	0–50 ppm	Thermo Environmental Instruments, Inc.	48C	0415406564
	PS-4	0–5,000 ppm			

In accordance with Appendix B, PS-4 and/or 4A of 40 CFR Part 75, Hines PB3 was required to perform the following quality assurance checks in order to certify each CEMS –

[1] A NO_x CEMS (which consists of a NO_x and O_2 monitor) required under 40 CFR Part 75 was also installed and certified on Units 3A and 3B. A NO_x CEMS certification application has been submitted under separate cover to both FL DEP and US EPA.

- Seven (7) day calibration drift test
- Response time test
- A minimum nine (9) run relative accuracy test audit (RATA)

As an additional quality assurance measure, a cylinder gas audit (CGA) was also performed on the CO analyzers as part of the initial certification process, even though CGAs are only required for ongoing (and not initial) quality assurance and control, as defined by 40 CFR Part 60, Appendix F.

2.0 CERTIFICATION TESTS

Hines PB3 successfully completed each of the required certification tests for the Unit 3A and 3B CEMS as of **November 1, 2005**. The CGA, 7-day calibration drift test, and response time test were completed by Spectrum Systems personnel. The RATA was conducted by TRC Cubix Corporation. Contact information for this certification program can be found in Appendix 6 of this certification application.

2.1 Cylinder Gas Audit (CGA)

For each of the two CEMS, a CGA test was performed on each range of the dual range CO analyzer in accordance with the procedures in 40 CFR Part 60, Appendix F, §5.1.2. The CGA tests were performed using EPA Protocol calibration gases corresponding to 20-30% and 50-60% of each analyzer range. The analyzers were challenged three times with each of the two calibration gases, without using the same calibration gas twice in succession. The equation used to determine the results of the CGA is as follows:

$$A = \left| \frac{C_m - C_a}{C_a} \right| \times 100$$

Where: A = Accuracy of the CEMS (%)
C_m = Average of the monitoring system responses
C_a = Cylinder tag value

Results of the CGA tests are acceptable if the CGA error is ≤ 15% of the audit gas concentration, or if the absolute value of the difference between the average of the monitor responses and the average of the audit gas concentrations is ≤ 5 ppm CO, whichever is least restrictive. Table 2-1 provides a summary of the CGA test results. Complete CGA printouts are located in Appendix 2 of this certification application.

Table 2-1. Summary of CGA Test Results

Unit	Date	Monitor Range	Level	Tag Value	Average Response	% of Tag Value	Performance Specification
3A	09/28/05	Low	Low	12.74	12.73	0.1	≤ 15% of tag value or ≤ ± 5 ppm
			Mid	27.54	26.70	3.1	
			High	Not Required			
	09/28/05	High	Low	1241	1269	2.3	
			Mid	2752	2777	0.9	
			High	Not Required			
3B	09/28/05	Low	Low	12.74	12.47	2.1	≤ 15% of tag value or ≤ ± 5 ppm
			Mid	27.54	27.80	0.9	
			High	Not Required			
	09/28/05	High	Low	1241	1362	9.8	
			Mid	2752	2749	0.1	
			High	Not Required			

2.2 Seven (7) Day Calibration Drift Test

Calibration drift tests were performed on each range of the dual-range CO analyzers once per day for seven (7) consecutive calendar days, at approximate twenty-four (24) hour intervals, while the subject unit was operating at more than 50% of normal load, as prescribed by 40 CFR Part 60, Appendix B, PS-2, §8.3. Each analyzer was challenged with two EPA Protocol gas concentrations corresponding to 0-20% and 50-100% of each instrument's span.

The 7-day CD test results are acceptable for the CO analyzer if none of the test results differ from the reference value of the calibration gas by more than 5% based on the instrument's span (for at least 6 out of the 7 test days).

The equation used to determine the calibration drift is:

$$CD = \left|\frac{C - M}{S}\right| \times 100$$

Where: CD= Percentage calibration drift based upon instrument span
C = Reference value of zero- or upscale-level calibration gas introduced into the CEMS
M = Actual monitoring system response to the calibration gas
S = Span of the instrument

Table 2-2 provides a summary of the 7-day calibration drift test results for the CO analyzers. The daily calibration printouts are presented in Appendix 3 of this certification application.

Table 2-2. Summary of 7-Day Calibration Drift Test Results

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3A	09/30/05 – 10/06/05	Low	0.5 ppm	0.2 ppm	≤ ± 2.5 ppm
		High	1.2 ppm	41.8 ppm	≤ ± 250 ppm
3B	09/30/05 – 10/06/05	Low	0.5 ppm	0.6 ppm	≤ ± 2.5 ppm
		High	1.6 ppm	40.0 ppm	≤ ± 250 ppm

[1]Highest zero-level absolute difference shown during 7-day calibration drift test period.
[2]Highest span-level absolute difference shown during 7-day calibration drift test period.
[3]For clarity, the performance specification is defined as an absolute difference, which corresponds to 5% of span.

2.3 Response Time Test

A response time test was performed on the low range of each CO analyzer using zero and span-level calibration gases according to the procedures outlined in 40 CFR Part 60, Appendix B, PS-4A, §8.3. Response time tests are not required under PS-4; hence, response time tests were not required on the high range of the CO analyzers.

In order to perform the response time test, zero gas was introduced into the CO analyzer while operating on the low range. When the CO analyzer output stabilized (i.e., no change greater than 1% of full scale for 30 seconds), the upscale CO calibration gas was introduced into the system. Once the upscale CO calibration gas was introduced into the system, the time required to reach 95% of the final stable value was recorded (i.e., the upscale response time). Next, the zero gas was reintroduced. Once the zero gas was reintroduced into the system, the time required to reach 95% of the final stable value was recorded (i.e., the downscale response time). This procedure was repeated three (3) times, and the mean upscale and downscale response times was then determined. The slower (i.e., longer) of the upscale and downscale response times was deemed the CO CEMS response time. The CO CEMS response time should not exceed 1.5 minutes (i.e., 90 seconds) to achieve 95% of the final stable value.

Table 2-3 provides a summary of the response time results for Units 3A and 3B. The 10-second data printouts are presented in Appendix 4 of this certification application.

Table 2-3. Summary of Response Time Test Results

3A	80 seconds	**90 seconds**	≤ 90 seconds
3B	80 seconds	**90 seconds**	

NOTE: Response times in **bold** (i.e., the slowest/longest time) indicate response time of CO CEMS.

2.4 Relative Accuracy Test Audit

A RATA was performed on each of the two CEMS by TRC Cubix Corporation in accordance with 40 CFR Part 60, Appendix B, PS-4A, §§ 8.1 and 13.2. Each RATA consisted of eight (8) 21-minute comparative test runs and one (1) 60-minute test run[2]. The reference method test team used EPA Reference Method 10 to make measurements of CO. A stratification test was also performed at each unit's test location prior to performing the RATAs. Table 2-4 provides a summary of the RATA test results. **The complete RATA discussion of results are included in Appendix 5 of this certification application.**

Table 2-4. Summary of CO RATA Results

3A	10/19-21/05	170	0.63 ppm	0.52 ppm	RA ≤ 10%[2]	RA ≤ 5%[3]	≤ ± 5 ppm[4]
3B	10/19-21/05	170	0.45 ppm	0.38 ppm			

[1]Under 40 CFR Part 60, no semi-annual RATA testing is required. All RATA testing is performed on an annual basis, regardless of the RATA results (provided that the RATA is passed).
[2]When the average RM value is used to calculate the RA.
[3]When the applicable emission standard is used to calculate the RA. For this particular source, the emission standard is in terms of CO ppm corrected to 15% O_2.
[4]When the RA is calculated as the absolute difference between the RM and CEMS plus the confidence coefficient. This was the performance specification utilized for this particular RATA.

Note also that new combined-cycle units such as Units 3A and 3B emit little to no CO emissions at high load. Due to a slightly negative CO CEMS calibration bias at the zero-level (which is not unusual), it was necessary to "round up" the Unit 3A CO CEMS ppm concentrations to 0 ppm during the RATA, in order to avoid the reporting of negative emissions. (The RATA results would have also been deemed as passing using the negative ppm values.)

[2] The ninth and final RATA run was 60 minutes in length in order to coincide with one of the three (3) compliance test runs required by the air permit.

Progress Energy

NSPS/BACT INITIAL COMPLIANCE TEST REPORT
Units 3A and 3B

for

Progress Energy – Hines Energy Complex
Bartow, Polk County, Florida

December 2005

Prepared By:

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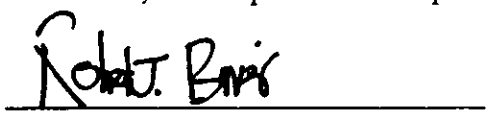
CERTIFICATION STATEMENT

Section IV, Appendix SC, Standard Condition No. 18. of Air Permit No. PSD-FL-330 requires "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."

I certify that, to the best of my knowledge and belief, that all data required and provided are true and correct, with respect to the test procedures used.



Robert J. Bivens
Senior Engineer I
Responsible for Test Protocol and Report Authorship, Project Oversight, and Quality Assurance
RMB Consulting & Research, Inc.

EXECUTIVE SUMMARY

The Hines Energy Complex has recently completed construction on two (2) combined-cycle turbine units (Power Block 3 – Units 3A and 3B) at its Bartow, Florida facility. As a result, the two units are subject to air emissions testing and reporting requirements as set forth by the United States Environmental Protection Agency in Title 40 of the Code of Federal Regulations Part 60 (40 CFR Part 60) for New Source Performance Standard Subpart GG and Best Available Control Technology.

The purpose of this test program was to determine the compliance status with specific air emission permit limits as contained in Air Permit No. PSD-FL-330, issued by the Florida Department of Environmental Protection. Emissions testing was performed for NO_x, CO, VOC, ammonia, and visible emissions on both units while firing both natural gas and No. 2 fuel oil at high load.

The following report shows that compliance was demonstrated on both units, for each of the required pollutants, at each fuel and load condition as required by the current air permit.

1.0 INTRODUCTION

Progress Energy's Hines Energy Complex – Power Block 3 (Hines PB3) has recently completed construction on two (2) combined-cycle turbine units (Units 3A and 3B) at its Bartow, Florida facility. As a result, the two units are subject to air emissions testing and reporting requirements as set forth by the United States Environmental Protection Agency (US EPA) in Title 40 of the Code of Federal Regulations Part 60 (40 CFR Part 60) for New Source Performance Standard (NSPS) Subpart GG and Best Available Control Technology (BACT). These requirements are administered by the Florida Department of Environmental Protection (FL DEP).

The purpose of the test program was to determine compliance with specific air emission permit limits as contained in FL DEP Air Permit No. PSD-FL-330. This report outlines the procedures that were followed, the test methods that were used, and any approved deviations from either the specific conditions and limitations as listed in the above referenced air permit, or from the test methods themselves.

For this test program, all emissions testing was performed by TRC Cubix Corporation. Overall project oversight, testing supervision, test protocol development, and final report generation was or is being provided by RMB Consulting & Research, Inc. (RMB). RMB personnel were also present for the entire duration of the test program. Contact information for this test program can be found in Appendix 10 of this report.

2.0 BACKGROUND

Testing was performed on the respective stack outlet (i.e., downstream of the heat recovery steam generator (HRSG)) of Units 3A and 3B. Air Permit No. PSD-FL-330, Section III, Condition No. 16 outlines the specific compliance testing requirements for Units 3A and 3B.

Compliance testing for oxides of nitrogen (NO_x), oxygen (O_2), carbon monoxide (CO), volatile organic compounds (VOCs), ammonia slip (NH_3 slip) and visible emissions (VE) was required for both units. Per the above referenced air permit, the testing of emissions was to be conducted with each respective unit operating at permitted capacity. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. For both Units 3A and 3B, this was specifically defined in the test protocol as at least 90 percent of 170 MW, or at least 153 MW. Testing was performed while separately firing natural gas and No. 2 fuel oil on each unit, while the appropriate fuel-specific control technologies were in normal operational mode.

Note also that a NO_x and CO CEMS relative accuracy test audit (RATA) was performed concurrently on each unit along with the compliance test program. The results of the NO_x and CO CEMS RATA (and other certification tests) have been submitted as a separate report, under separate cover. Due to the concurrent nature of testing, FL DEP previously approved that the data assimilated during the NO_x and CO relative accuracy test audits (RATAs) could also be used as the NO_x and CO compliance testing data while firing natural gas[1]. That is, RATA Runs 1-3 = Compliance Run 1, etc. since three 21-minute RATA runs provide at least 60 minutes worth of compliance data[2]. All test runs for No. 2 fuel oil were 60 minutes in length.

These pollutants, the prescribed load/fuel conditions, and their respective emission limitations are described in Table 2-1. This table also describes the applicable test methods that were used to test for each pollutant as well as the run times of each reference method (RM).

[1] The RATAs were conducted while combusting natural gas only.
[2] Due to TRC Cubix's sampling and data acquisition limitations, the VOC test runs while combusting natural gas were also 21 minutes in length during the RATA (where three 21-minute runs comprised a single compliance test run).

Table 2-1. Initial Compliance Test Matrix – Units 3A and 3B

Pollutant	Method	Fuel	Load Level	# of Runs	Duration	Permit Limit
NO_x	7E	Gas	≥ 153 MW	9	21 min/run	2.5 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	10 ppm @ 15% O_2
O_2	3A	Gas	≥ 153 MW	9	21 min/run	N/A
		Oil	≥ 153 MW	3	60 min/run	N/A
NH_3 Slip	CTM-027[2]	Gas	≥ 153 MW	3	60 min/run	5 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	5 ppm @ 15% O_2
CO	10	Gas	≥ 153 MW	9	21 min/run	10 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	20 ppm @ 15% O_2
VOC	25A	Gas	≥ 153 MW	9	21 min/run	2 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	10 ppm @ 15% O_2
VE	9	Gas	≥ 153 MW	1	30 min/run	10 % per 6-minute block
		Oil	≥ 153 MW	1	30 min/run	10 % per 6-minute block

[1]Permitted ppm limits expressed as ppm dry.
[2]Moisture determinations were made simultaneously (using RM 4 procedures) in order to convert VOC ppmw to ppmd.

Where possible and necessary, all pollutants were concurrently sampled. While firing natural gas, however, both units tripped during the 9th and final NO_x/CO RATA and VOC run. At the time of the trip, the 3rd and final ammonia slip test run was already completed on both units. However, the final NO_x/CO RATA and VOC run (and hence the final 21 minutes of the compliance test run) were not completed on either unit. As a result, once the units were brought back on-line to fire natural gas, a 60 minute test run (which doubled as the 9th RATA run) was performed in order to provide 60 minutes of continuous data to demonstrate compliance with the required pollutants (with the exception of ammonia, which was already completed). For clarity, Table 2-2 summarizes the run layout for each pollutant, fuel, and unit.

Table 2-2. Run Layout for Hines PB3 Test Program – Units 3A and 3B

Pollutant	Natural Gas Run No.:		No. 2 Fuel Oil Run No.:	
	Compliance	RATA	Compliance	RATA
NO_x, CO, and VOC	1	1-3	Runs 1-3 performed concurrently for all pollutants	N/A[3]
	2	4-6		
	3	9		
NH_3	1	1-3		
	2	4-6		
	3	7-8[4]		
O_2	O_2 was measured during all runs			

[3] RATA testing is not required while firing No. 2 fuel oil (i.e., a secondary fuel).

[4] The NO_x ppm measured during the 3rd compliance run for ammonia (on both units) is shown by referencing the NO_x ppm measured during RATA Runs 7 and 8.

3.0 SUMMARY OF COMPLIANCE TESTING RESULTS

Compliance was demonstrated for each of the required pollutants at each fuel and load condition as required by the current air permit. Tables 3-1 through 3-4 summarize the results (based upon the 3-run averages) of this testing program. Appendix 1 of this report contains the more detailed and comprehensive run-by-run results.

Table 3-1. Summary of Initial Compliance Testing Results – Unit 3A Natural Gas

Load Level, (MW)	Heat Input, (mmBtu/hr)[1]	NH_3 Injection Rate, (lb/hr)	Pollutant	Test Result	Permit Limit[2,3]	Compliance Indicated?
170.4	1770.0[4]	195.7	NO_x ppm	2.33	**2.5**	**Yes**
			CO ppm	0.47	**10**	**Yes**
			VOC ppm	0.76	**2**	**Yes**
			NH_3 ppm	3.92	**5**	**Yes**
			VE %	0.0	**10**	**Yes**

[1]Heat input based upon a gross calorific (GCV) value of 1,058 Btu/scf during testing.
[2]Permit limits (in ppm) and test results are corrected to 15% O_2.
[3]VE % permit limits and test results are based upon 6-minute block averages.
[4]Average ambient temperature during testing was 84 °F.

Table 3-2. Summary of Initial Compliance Testing Results – Unit 3B Natural Gas

Load Level, (MW)	Heat Input, (mmBtu/hr)[1]	NH_3 Injection Rate, (lb/hr)	Pollutant	Test Result	Permit Limit[2,3]	Compliance Indicated?
170.9	1745.1[4]	148.2	NO_x ppm	2.19	**2.5**	**Yes**
			CO ppm	0.53	**10**	**Yes**
			VOC ppm	0.75	**2**	**Yes**
			NH_3 ppm	3.01	**5**	**Yes**
			VE %	0.0	**10**	**Yes**

[1]Heat input based upon a GCV value of 1,058 Btu/scf during testing.
[2]Permit limits (in ppm) and test results are corrected to 15% O_2.
[3]VE % permit limits and test results are based upon 6-minute block averages.
[4]Average ambient temperature during testing was 84 °F.

Table 3-3. Summary of Initial Compliance Testing Results – Unit 3A No. 2 Fuel Oil

Load Level (MW)	Heat Input (mmBtu/hr)[1]	NH_3 Injection Rate (lb/hr)	Pollutant	Test Result	Permit Limit[2,3]	Compliance Indicated?
168.8	1695.6[4]	296.9	NO_x ppm	8.20	**10**	**Yes**
			CO ppm	0.42	**20**	**Yes**
			VOC ppm	0.22	**10**	**Yes**
			NH_3 ppm	3.45	**5**	**Yes**
			VE %	0.0	**10**	**Yes**

[1]Heat input based upon a GCV value of 19,790 Btu/lb and a density of 6.72 lb/gal during testing.
[2]Permit limits (in ppm) and test results are corrected to 15% O_2.
[3]VE % permit limits and test results are based upon 6-minute block averages.
[4]Average ambient temperature during testing was 76 °F.

Table 3-4. Summary of Initial Compliance Testing Results – Unit 3B No. 2 Fuel Oil

Load Level (MW)	Heat Input (mmBtu/hr)[1]	NH_3 Injection Rate (lb/hr)	Pollutant	Test Result	Permit Limit[2,3]	Compliance Indicated?
166.7	1766.8[4]	299.5	NO_x ppm	7.88	**10**	**Yes**
			CO ppm	0.39	**20**	**Yes**
			VOC ppm	0.30	**10**	**Yes**
			NH_3 ppm	3.10	**5**	**Yes**
			VE %	0.0	**10**	**Yes**

[1]Heat input based upon a GCV value of 19,790 Btu/lb and a density of 6.72 lb/gal during testing.
[2]Permit limits (in ppm) and test results are corrected to 15% O_2.
[3]VE % permit limits and test results are based upon 6-minute block averages.
[4]Average ambient temperature during testing was 83 °F.

NOTE

As specifically defined in the previously submitted test protocol, all testing was performed at greater than 90 percent of 170 MW, which corresponds to at least 153 MW. Note that the 170 MW value is the "rated" load of each unit, and may differ based upon the ambient conditions and fuel characteristics in evidence at the time of testing. As such, all testing was "virtually" performed at 100 percent of the maximum achievable load (and subsequent, resultant heat input levels) for each respective day and test condition.

ATTACHMENT PEF-EU3-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT PEF-EU3-IV3
ALTERNATIVE METHODS OF OPERATION

Each gas turbine fires natural gas as the primary fuel and distillate oil as a restricted alternative fuel.

Fuel usage while burning natural gas at the site shall not contain more than 1.0 grains of Sulfur per 100 standard cubic feet of natural gas. Fuel usage of both emission units while burning fuel oil at the site, shall not exceed 19,703,000 gallons (LHV) per year during any consecutive 12 month period.

Fuel Oil Operation

The maximum heat input rate, based on the higher heating value (HHV) of No. 2 fuel oil at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 2,155 MMBtu/hr when firing No. 2 or superior grade of distillate fuel oil.

The amount of fuel oil burned at this site (in BTU's) will not exceed the amount of natural gas burned at this site (in BTU's) during any consecutive 12-month period **[Rule 62-210.200, F.A.C. (BACT)]**.

Natural Gas Operation

The maximum heat input rate, based on the higher heating value (HHV) of natural gas at ambient conditions of 59°F temperature, 100% load, and 14.7 psi pressure will not exceed 2,048 MMBtu/hr when firing natural gas.

Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, fuels and evaporative cooling.

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [4] of [5]
Auxiliary Steam Boiler

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Natural gas fired steam boiler rated at 99 MMBtu/hr. The boiler provides steam for periods of combustion turbine startup or quick startup out of a short-term shutdown.

3. Emissions Unit Identification Number: **003**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **The emissions unit is regulated under NSPS - 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.**

EMISSIONS UNIT INFORMATION
Section [4] of [5]
Auxiliary Steam Boiler

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   None

2. Control Device or Method Code(s):

EMISSIONS UNIT INFORMATION
Section [4] of [5]
Auxiliary Steam Boiler

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **99** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **1,000** hours/year
6. Operating Capacity/Schedule Comment: **The boiler provides steam for periods of Combustion Turbine startup or quick startup out of a short-term shutdown.**	

EMISSIONS UNIT INFORMATION
Section [4] of [5]
Auxiliary Steam Boiler

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Aux Boiler**		2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **22** feet	7. Exit Diameter: **2** feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: **110,000** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment:		

EMISSIONS UNIT INFORMATION
Section [4] of [5]
Auxiliary Steam Boiler

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.094**	5. Maximum Annual Rate: **94.3**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,050**
10. Segment Comment: **Based on 99 MMBtu/hr, 1000 hr/yr, 1,050 MMBtu/MMCF as per Subsection B. of Title V Permit 1050234-008-AV(1050234-012-AV).**		

Segment Description and Rate: Segment _ of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
SO_2			WP
NO_x			EL
CO			NS
VOC			NS

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete for each pollutant identified in Subsection E if applying for an air construction permit or concurrent processing of an air construction permit and a revised or renewal Title V permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **9.9** lb/hour **4.95** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.1 lb/MMBtu** Reference: **PSD-FL-195B, Title V Permit No 1050234-001-AV**	7. Emissions Method Code: **2**
8. Calculation of Emissions:	
9. Pollutant Potential/Estimated Fugitive Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete if the pollutant identified in Subsection F1 is or would be subject to a numerical emissions limitation.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **9.9** lb/hour **4.95** tons/year
5. Method of Compliance: **Natural Gas Combustion.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas firing: PSD-FL-195B, Title V Permit No 1050234-001-AV**	

Allowable Emissions Allowable Emissions _ of

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

Allowable Emissions Allowable Emissions _____ of _____

1. Basis for Allowable Emissions Code:	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units:	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance:	
6. Allowable Emissions Comment (Description of Operating Method):	

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9; Per Specific Condition B.12 of Title V Permit 1050234-008-AV, no annual testing required if burn only natural gas or burn liquid fuels for less than 400 hrs per year.**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule ☐ Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU1-I2** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID:
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: ☒ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☒ Not Applicable

Additional Requirements Comment

III. EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Application - For Title V air operation permitting only, emissions units are classified as regulated, unregulated, or insignificant. If this is an application for Title V air operation permit, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each regulated and unregulated emissions unit addressed in this application for air permit. Some of the subsections comprising the Emissions Unit Information Section of the form are optional for unregulated emissions units. Each such subsection is appropriately marked. Insignificant emissions units are required to be listed at Section II, Subsection C.

Air Construction Permit or FESOP Application - For air construction permitting or federally enforceable state air operation permitting, emissions units are classified as either subject to air permitting or exempt from air permitting. The concept of an "unregulated emissions unit" does not apply. If this is an application for air construction permit or FESOP, a separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air permitting are required to be listed at Section II, Subsection C.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit Application – Where this application is used to apply for both an air construction permit and a revised/renewal Title V air operation permit, each emissions unit is classified as either subject to air permitting or exempt from air permitting for air construction permitting purposes and as regulated, unregulated, or insignificant for Title V air operation permitting purposes. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** A separate Emissions Unit Information Section (including subsections A through I as required) must be completed for each emissions unit subject to air permitting addressed in this application for air permit. Emissions units exempt from air construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

If submitting the application form in hard copy, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application must be indicated in the space provided at the top of each page.

EMISSIONS UNIT INFORMATION
Section [5] of [5]
Relocatable Diesel Generator

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.)

   ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit.

   ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one)

   ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent).

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions.

   ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.

2. Description of Emissions Unit Addressed in this Section:
   Relocatable diesel generator(s) with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts.

3. Emissions Unit Identification Number: **7775047 -001**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A			**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: Model Number:

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment: **The generators may be relocated to any of the following facilities:**
    1. **Crystal River Plant, Powerline Road, Red Level, Citrus County.**
    2. **Bartow Plant, Weedon Island, St. Petersburg, Pinellas County.**
    3. **Higgins Plant, Shore Drive, Oldsmar, Pinellas County.**
    4. **Bayboro Plant, 13th Ave. & 2nd St. South, St. Petersburg, Pinellas County.**
    5. **Wildwood Reclamation Facility, State Road 462, 1 mi. east of U.S. 301, Wildwood, Sumter County.**
    6. **Hines Energy Complex, County Road 555, 1 mi. southwest of Homeland, Polk County.**
    7. **Anclote Power Plant, 1729 Baileys Road, Holiday, Pasco County**

EMISSIONS UNIT INFORMATION

Section [5] of [5]

Relocatable Diesel Generator

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
   None

2. Control Device or Method Code(s):

B. EMISSIONS UNIT CAPACITY INFORMATION

(Optional for unregulated emissions units.)

Emissions Unit Operating Capacity and Schedule

1. Maximum Process or Throughput Rate:	
2. Maximum Production Rate:	
3. Maximum Heat Input Rate: **25.74** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **52** weeks/year	**7** days/week **2,970** hours/year
6. Operating Capacity/Schedule Comment: **Relocatable diesel generator(s) with a maximum (combined) heat input of 25.74 MMBtu/hour while being fueled by 186.3 gallons of new No. 2 fuel oil per hour with a maximum (combined) rating of 2460 kilowatts.**	

EMISSIONS UNIT INFORMATION
Section [5] of [5]
Relocatable Diesel Generator

C. EMISSION POINT (STACK/VENT) INFORMATION
(Optional for unregulated emissions units.)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram: **Relocatable Gen**	2. Emission Point Type Code: **1**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Each generator exhausts through a single stack.**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:		
5. Discharge Type Code: **V**	6. Stack Height: **15** feet	7. Exit Diameter: **1** feet
8. Exit Temperature: **1,004** °F	9. Actual Volumetric Flow Rate: **7,283** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: **17** East (km): **414.4** North (km): **3073.9**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment: **Representative of typical 820 KW diesel generators. Actual stack parameters will vary depending upon manufacturer and model.**		

EMISSIONS UNIT INFORMATION
Section [5] of [5]
Relocatable Diesel Generator

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Diesel Fuel Oil.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand Gallons Burned**	
4. Maximum Hourly Rate: **0.18**	5. Maximum Annual Rate: **535**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **141.2**
10. Segment Comment: **Based on 25.74 MMBtu/hr, 2970 hr/yr.**		

Segment Description and Rate: Segment _ of

1. Segment Description (Process/Fuel Type):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment:		

E. EMISSIONS UNIT POLLUTANTS

List of Pollutants Emitted by Emissions Unit

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
SO_2			NS
NO_x			NS
CO			NS
VOC			NS

G. VISIBLE EMISSIONS INFORMATION

Complete if this emissions unit is or would be subject to a unit-specific visible emissions limitation.

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment:	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment: **FDEP Rule 62-210.700(2); allowed for 2 hours (120 minutes) per 24 hours for startup, shutdown, and malfunction.**	

H. CONTINUOUS MONITOR INFORMATION

Complete if this emissions unit is or would be subject to continuous monitoring.

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _ of

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule ☐ Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

I. EMISSIONS UNIT ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Process Flow Diagram (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-FI-C2** ☐ Previously Submitted, Date _____

2. Fuel Analysis or Specification (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☒ Attached, Document ID: **PEF-EU5-I2** ☐ Previously Submitted, Date _____

3. Detailed Description of Control Equipment (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____

4. Procedures for Startup and Shutdown (Required for all operation permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____
   ☐ Not Applicable (construction application)

5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: ☐ Previously Submitted, Date _____
   ☒ Not Applicable

6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID:
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____
   ☐ To be Submitted, Date (if known):_____
   Test Date(s)/Pollutant(s) Tested: _____
   ☒ Not Applicable
   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.

7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Air Construction Permit Applications

1. Control Technology Review and Analysis (Rules 62-212.400(6) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e))
   ☐ Attached, Document ID: _____ ☒ Not Applicable
2. Good Engineering Practice Stack Height Analysis (Rule 62-212.400(5)(h)6., F.A.C., and Rule 62-212.500(4)(f), F.A.C.)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only)
   ☐ Attached, Document ID: _____ ☒ Not Applicable

Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements
   ☐ Attached, Document ID: ☒ Not Applicable
2. Compliance Assurance Monitoring
   ☐ Attached, Document ID: _____ ☒ Not Applicable
3. Alternative Methods of Operation
   ☐ Attached, Document ID: ☒ Not Applicable
4. Alternative Modes of Operation (Emissions Trading)
   ☐ Attached, Document ID: _____ ☒ Not Applicable
5. Acid Rain Part Application
   ☐ Certificate of Representation (EPA Form No. 7610-1)
      ☐ Copy Attached, Document ID:
   ☐ Acid Rain Part (Form No. 62-210.900(1)(a))
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
      ☐ Attached, Document ID: _____
      ☐ Previously Submitted, Date: _____
   ☐ Not Applicable

Additional Requirements Comment

ATTACHMENT PEF-EU5-I2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT PEF-EU5-I2

DIESEL FUEL ANALYSIS

Typical Properties of Diesel Fuel:

Property	ASTM Test Method	Grade No. 2-Diesel
Flash Point, ° C. min.	D 93	52
Water & Sediment, % vol, max	D 2709	0.05
	D 1796	...
Distillation Temperature, ° C 90 % % vol Recovered	D 86	
min		282
max		338
Kinematic Viscosity, mm2/S at 40° C	D 445	
min		1.9
max		4.1
Ash % mass, max	D 482	0.01
Sulfur, % mass, max	D 2622	...
	D 129	0.50
Copper strip corrosion rating max 3 h at 50° C	D 130	No. 3
Cetane number, min	D 613	40
One of the following properties must be met:		
(1) Cetane index, min	D 976	...
(2) Aromaticity, 5 vol. max	D 1319	...
Operability Requirements	D 2500	A
Cloud Point, °C, max	D 4539/	
or	D 6371	
LTFT/CFPP, °C, max	D 2500	
Ramsbottom carbon residue on 10% distillation residue, % mass, max	D 524	0.35