Adams, Patty

From: Harvey, Mary
Sent: Wednesday, January 31, 2007 9:51 AM
To: Linero, Alvaro; Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Quillian, Ann [mailto:Ann.Quillian@pgnmail.com]
Sent: Wednesday, January 31, 2007 9:29 AM
To: Harvey, Mary
Cc: Jackson, Rufus; Sanchez, Terese
Subject: RE: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Your e-mails was received with five (5) attachments.

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Monday, January 29, 2007 2:05 PM
To: Quillian, Ann; Jackson, Rufus; little.james@epa.gov
Cc: Linero, Alvaro; Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Harvey, Mary
Sent: Monday, January 29, 2007 1:56 PM
To: 'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Wednesday, January 31, 2007 8:42 AM
To: Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Meredith_Bond@fws.gov [mailto:Meredith_Bond@fws.gov]
Sent: Tuesday, January 30, 2007 4:03 PM
To: Harvey, Mary
Subject: Re: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Mary,

Thank you - US Fish and Wildlife Service - Branch of Air Quality did receive this e-document transmittal.

-- Meredith Bond

CDR Meredith Bond, P.E., USPHS
Deputy Chief
U.S. Fish and Wildlife Service
Branch of Air Quality
7333 W Jefferson Ave., Suite 375
Lakewood, CO 80235
303-914-3808
303-969-5444 fax
Meredith_Bond@fws.gov

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

01/29/2007 11:55 AM

To <sosbourn@golder.com>, <dee_morse@nps.gov>, <meredith_bond@fws.gov>, <phesslin@co.pinellas.fl.us>, "Nasca, Mara" <Mara.Nasca@dep.state.fl.us>, <mayor@spete.org>, <sspratt@pinellascounty.org>

cc "Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>, "Adams, Patty" <Patty.Adams@dep.state.fl.us>, "Gibson, Victoria" <Victoria.Gibson@dep.state.fl.us>

Subject Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

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Adams, Patty

From: Harvey, Mary
Sent: Monday, January 29, 2007 4:17 PM
To: Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Monday, January 29, 2007 4:06 PM
To: Harvey, Mary
Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility # 1030011-010 AC-FINAL

Return Receipt

Your document:	Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL
was received by:	Dee Morse/DENVER/NPS
at:	01/29/2007 02:06:12 PM

Adams, Patty

From: Harvey, Mary
Sent: Tuesday, January 30, 2007 3:51 PM
To: Adams, Patty
Subject: FW: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility # 1030011-010 AC-FINAL

-----Original Message-----
From: Little.James@epamail.epa.gov [mailto:Little.James@epamail.epa.gov]
Sent: Tuesday, January 30, 2007 3:04 PM
To: Harvey, Mary
Subject: Re: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility # 1030011-010 AC-FINAL

Received

James W. (Jim) Little
U.S. Environmental Protection Agency, Region 4 Air, Pesticides, and Toxics Management Division
61 Forsyth St., SW
Atlanta, GA 30303-8960
Phone: (404) 562-9118
Fax: (404) 562-9019
E-mail: little.james@epa.gov

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>
01/29/2007 02:05 PM

To: Ann.Quillian@pgnmail.com, rufus.jackson@pgnmail.com, James Little/R4/USEPA/US@EPA
cc: "Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>, "Adams, Patty" <Patty.Adams@dep.state.fl.us>
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Harvey, Mary
Sent: Monday, January 29, 2007 1:56 PM
To: 'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria

Adams, Patty

From: Harvey, Mary
Sent: Monday, January 29, 2007 3:27 PM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Osbourn, Scott [mailto:Scott_Osbourn@golder.com]
Sent: Monday, January 29, 2007 3:26 PM
Subject: Read: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Your message

To: Scott_Osbourn@golder.com
Subject:

was read on 1/29/2007 3:26 PM.

Adams, Patty

From: Harvey, Mary
Sent: Monday, January 29, 2007 3:32 PM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Zhang-Torres
Sent: Monday, January 29, 2007 3:31 PM
To: Harvey, Mary
Subject: RE: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Mary,

We got the permit. Thanks.

Cindy Zhang-Torres

From: Nasca, Mara
Sent: Monday, January 29, 2007 2:59 PM
To: Zhang-Torres
Cc: Prickett, Patricia
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Cindy,
Please reply to Mary....thanks

From: Harvey, Mary
Sent: Monday, January 29, 2007 1:56 PM
To: 'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

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Thank you,

Adams, Patty

From: Harvey, Mary
Sent: Monday, January 29, 2007 2:59 PM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Nasca, Mara
Sent: Monday, January 29, 2007 2:58 PM
To: Harvey, Mary
Subject: Read: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Your message

To:	'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'
Cc:	Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject:	Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL
Sent:	1/29/2007 1:56 PM

was read on 1/29/2007 2:58 PM.

From: Harvey, Mary
Sent: Monday, January 29, 2007 2:20 PM
To: Linero, Alvaro; Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

From: Hessling, Peter A [mailto:phesslin@co.pinellas.fl.us]
Sent: Monday, January 29, 2007 2:13 PM
To: Harvey, Mary
Subject: RE: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Received.

Peter Hessling
Air Quality Division Director
Pinellas Co. Dept. of Envir. Mgt.

From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Monday, January 29, 2007 1:56 PM
To: sosbourn@golder.com; dee_morse@nps.gov; meredith_bond@fws.gov; Hessling, Peter A; Nasca, Mara; mayor@spete.org; Spratt, Stephen M
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary

Sent: Monday, January 29, 2007 1:56 PM

To: 'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'

Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria

Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

Attachments: 1030011.010.AC.F_pdf.zip

Dear Sir/Madam:

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Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Monday, January 29, 2007 2:05 PM
To: 'Ann.Quillian@pgnmail.com'; 'rufus.jackson@pgnmail.com'; 'little.james@epa.gov'
Cc: Linero, Alvaro; Adams, Patty
Subject: FW: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL
Attachments: FINALAppendix381 - Facility #1030011-010-AC-FINAL.PDF; FINALPERMIT381 - Facility #1030011-010-AC-FINAL.PDF; FINDET - Facility #1030011-010-AC-FINAL.PDF; FNOTICE381- Facility #1030011-010-AC-FINAL.PDF; Signed Documents for Facility #1030011-010-AC-FINAL.pdf

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From: Harvey, Mary
Sent: Monday, January 29, 2007 1:56 PM
To: 'sosbourn@golder.com'; 'dee_morse@nps.gov'; 'meredith_bond@fws.gov'; 'phesslin@co.pinellas.fl.us'; Nasca, Mara; 'mayor@spete.org'; 'sspratt@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Florida Power Corporation dba Progress Energy, Florida, Inc. - Facility #1030011-010 AC-FINAL

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Thank you,

DEP, Bureau of Air Regulation

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Air Permit by:

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative: Mr. Rufus Jackson

DEP File No.: 1030011-010-AC
Permit No. PSD-FL-381
P.L. Bartow Power Plant
Repowering Project
Pinellas County

Enclosed is the Final Permit Number PSD-FL-381 (1030011-010-AC) to construct/install a 1280 MW natural gas-fueled combined cycle unit system and a 195 MW natural gas-fueled simple cycle unit at the P.L. Bartow Power Plant at Weedon Island in St Petersburg, Pinellas County. The project includes and requires the shutdown of three existing residual oil-fueled steam electrical generating units. This permit is issued pursuant to Chapter 403, Florida Statutes.

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, 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 L. Vielhauer
Trina L. 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) and all copies were sent electronically (with Received Receipt) before the close of business on 1/29/07 to the person(s) listed:

Rufus Jackson, PEF: rufus.jackson@pgnmail.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Ann Quillian, P.E., PEF: ann.quillian@pgnmail.com
Dee Morse, NPS: dee_morse@nps.gov
Meredith Bond, U.S. FWS: meredith_bond@fws.gov
Peter Hessling, PCDEM: phesslin@pinellascounty.org
Jim Little, EPA: little.james@epa.gov
Mara Nasca, DEPSWD: mara.nasca@dep.state.fl.us
Mayor, City of St. Petersburg: mayor@stpete.org
Administrator, Pinellas County: sspratt@pinellascounty.org

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.

[signature] 1/29/07
(Clerk) (Date)

Department of Environmental Protection

Jeb Bush
Governor

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

Colleen M. Castille
Secretary

PERMITTEE

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Mr. Rufus Jackson

DEP File No. 1030011-010-AC
Permit No. PSD-FL-381
PEF P.L. Bartow Power Plant
Plant Repowering Project
Pinellas County
SIC No. 4911
Expires: March 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,280 megawatt (MW) combined cycle unit and one nominal 195 MW simple cycle unit at the Progress Energy Florida (PEF) P.L. Bartow Power Plant located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County.

Three existing fossil fuel fired steam generators designated as Units 1, 2 and 3 with a total nominal capacity of 465 MW will be shut down as part of this project.

The UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

STATEMENT OF BASIS

This 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.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. 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

Trina L Vielhauer for 1/26/07

Joseph Kahn, Director
Division of Air Resource
Management

(Date)

FINAL DETERMINATION

Florida Power Corporation dba
Progress Energy Florida, Inc.
Bartow Plant Repowering Project
DEP File No.: PSD-FL-381 (1030011-010-AC)

An Intent to Issue an Air Construction Permit was sent to Florida Power Corporation doing business as Progress Energy Florida, Inc. (the Company). The project is to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit with a total nominal electrical generating capacity of 1475 megawatts at the P.L. Bartow Power Plant at Weedon Island in St. Petersburg, Pinellas County.

The Company will permanently shut down three residual oil-fueled steam electrical generating units at the facility thus generating contemporaneous emissions reductions for several pollutants including nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}) and sulfuric acid mist (SAM). A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code for emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The Public Notice of Intent to Issue Air Construction Permit was published in the St. Petersburg Times on December 13, 2006. The proof of the Public Notice was received by the Department on January 3, 2007.

No comments were received from the public or the reviewing agencies with the exception of some minor comments regarding the numbering of emission units received from the Pinellas County Department of Environmental Management (the County). No requests for a public meeting or an administrative hearing were received.

Comments were received from the Company regarding the Draft Permit. Their comments are related to:

- Minor changes in the description of the project;
- Numeration of the emissions points (same as the County's comments);
- The compliance, monitoring and reporting requirements of the Federal New Source Performance Standards (NSPS) and the Department's BACT requirements; and
- Clarification on the permitting language of some conditions.

The comments from the Company are paraphrased below in *italics* and are followed by the Department's responses (in regular script) and permit changes shown in underlined (additions) and ~~strikethrough~~ (deletions) format:

1. Section I. Facility and Project Description

   Comment:

   The pipeline heating boiler and the relocatable diesel generator(s) are considered to be regulated emission units (see Sections III.B. and III.D. of Title V Permit 1030011-009-AV). The language in this paragraph is such that it includes these two emission units in the unregulated/insignificant emissions units. Please correct.

   Response:

   The Department will correct the facility description regarding the mentioned existing equipment as described by the Company and consistent with the Title V Operation Permit.

2. <u>Section I. Facility and Project Description (Page 2) and Emissions Units Description Table (Page 6)</u>

<u>Comment:</u>

The emission unit ID numbers listed are already assigned to unregulated emission units at the site. Please correct them with the emission unit ID numbers that would be generated by the ARMS database. These new emission unit ID numbers are expected to begin with number 038. The emission unit ID numbers are already assigned and should be changed.

<u>Response:</u>

The Department concurs with the Company's and the County's requests to correct the ID numbers to reflect the ones that will actually be assigned by the Department's Air Resource Management System (ARMS). The numeration of the new emissions units authorized by this permit will be numbered from 038 to 046.

3. <u>Section III. A. Condition 3. NESHAP Requirements</u>

<u>Comment:</u>

Please find attached a copy of an electronic mail message from EPA that confirms that the gas-fired stationary combustion turbine definition is based on actual hours of fuel oil burning operation per calendar year. Though the Bartow Repowering project is requesting the total aggregate limitation of 5000 hours per year of distillate oil firing, until which time the site exceeds the 1000 hours in a calendar year 40 CFR 63, Subpart YYYY would not apply.

<u>Response:</u>

The Company requested an aggregate total permitted usage of distillate fuel oil of <u>5000 hours</u> per year in the original application. The Department reasonably concluded when reviewing the application that during some years distillate fuel use by the facility will actually exceed 1000 hours and that Subpart YYYY, a rule for the control of hazardous air pollutants from stationary combustion turbines, will apply.

The Department believes a project-specific determination is necessary before considering removal of the otherwise applicable rule provisions. The Department contacted EPA Region 4 and its staff will provide a project-specific determination.

The Department will review and if necessary revise the condition in accordance with EPA's future written project-specific guidance on the matter. The Company does not wish to take a lower limit on fuel oil use than the requested 5000 hours. Because the Company wishes to receive the permit promptly, the Department will proceed with final issuance and will re-open the permit after receiving the requested project-specific guidance.

4. <u>Section III. A. Condition 8. Selective Catalytic Reduction Systems</u>

<u>Comment:</u>

Please change the first sentence to align with the last sentence of the same condition that the SCR system operation is not required when NO_x emission limits are met without their use. This change is as follows: "<u>Selective Catalytic Reduction Systems</u>: The permittee is <u>authorized to</u> ~~shall~~ install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit."

Response:

The Department agrees with the comment. The project avoided the requirements for the Prevention of Significant Deterioration (PSD) and a BACT determination for NO_X by shutting down older and more polluting units and complying with a separate new rule (40 CFR 60, Subpart KKKK) that limits NO_X emissions to 15 parts per million (ppm) when burning gas and 42 ppm when burning fuel oil. The Department has reasonable assurance that the 15 and 42 ppm NO_X limits will be achieved by the whether or not SCR (i.e. ammonia injection) systems are employed. Therefore installation of SCR systems is authorized and (as already indicated in the permit) their operation is not required. Section III. A. Condition 8 is changed as follows:

Selective Catalytic Reduction Systems: The permittee is authorized to ~~shall~~ install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use. [Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

5. Section III. A. Condition 12. Permitted Capacity- Combustion Turbines

Comment:

Please correct the typo in the first sentence of Condition 12 as follows: "Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the ~~lower~~ higher heating value (HHV) of each fuel, and 100% load)...."

Response:

The Department agrees with the comment. By specifying the higher heating value, the requested correction will actually reduce the stated "nominal heat input rate". Section III. A. Condition 12 is corrected as follows:

Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the ~~lower~~ higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon CT characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Rule 62-210.200(Definitions - PTE), F.A.C.]

6. Section III. A. Condition 14. (opening paragraph) Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2, and 3

Comment:

The second sentence of the opening paragraph limits operation to only the initially chosen CTs. If one or both of these initial CTs were to have operational and logistical problems, it would result in the need to operate one of the other two CTs in its place. Please change this language to address such a scenario, but still limits to only two CTs operated during this temporary period;

Response:

The Department will not change this condition at this time. The Company can request a modification of this permit in the future with a more complete assessment of the scenario(s) envisioned and the impacts on emissions and preservation of "netting" to avoid PSD.

7. Section III. A. Condition 14.a. (second bullet) Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2, and 3

Comment:

Restriction on SC Operation, second Bullet. The thirty (30) calendar day time limit to complete the certification of the NO_X CEMS under 40 CFR 75 will be difficult to meet, as there may be initial operational and logistical problems. PEF is requesting that the time frame be changed to 30 ***operating*** *days to complete the certification.*

Response:

It is not certain that the two subject combustion turbines will actually operate 30 calendar days in simple cycle prior to the permanent shutdown of residual fuel oil fired Units 1, 2 and 3. Therefore the requested change opens up the possibility that there will not be sufficient data to confirm that the project will comply with the requirement to limit NO_X emissions to less than 39 tons during the temporary simple cycle operation period.

The Department will modify the requirement to reflect 30 operating days but will also require that the certification be accomplished within 60 calendar days. Taken together, the requirements will comply with 40 CFR 75 – Continuous Emission Monitoring and with the Department's reasonable assurance provisions. The Department will modify Section III. A. Condition 14.a. (second bullet) as follows:

Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

a. *Restriction on SC Operation*:

- The combined operation of the two CTs shall not exceed 1,100 hours.
- A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 ~~calendar~~ operating days but not later than 60 calendar days after ~~of~~ startup of the CTs.
- Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period. Data recorded before and after CEMS certification shall be included in the calculation.

The rest of this condition remains unchanged.

8. Section III. A. Condition 15.b. and 15.c. Restricted Operation

Comment:

Please make the following suggested changes to the distillate oil CT firing as well as the DB operation. Also, please change the similar language in the fourth paragraph in Section I. General Information – Facility and Project Description (Page 2 of draft permit). Note the comments in items 4 and 15 of this correspondence.

"...b. Distillate oil firing is limited to ~~1,000 hours per CT (i.e.~~ 5,000 hours total aggregate for all five CTs~~)~~ during any consecutive 12-month period.

" c. Operation of the DBs is limited to ~~2,434 hours per DB (i.e.~~ 9,736 hours aggregate for four DBs~~)~~ during any consecutive 12-month period...."

Response:

The language in the permit is consistent with the public notice for this project that states:

"Low sulfur (0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five CTGs. The gas-fueled duct burner within each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam) augmentation mode for 1,688 hours per year."

The Department will not change this condition at this time. The Company can request a modification of this permit in the future with a more complete assessment of the scenario(s) envisioned and the impacts on emissions and preservation of "netting" to avoid PSD.

9. Section III. A. Condition 16.a. Methods of Operation Simple Cycle (SC) Operation

Comment:

Please correct the typographical error by changing the last word of Condition 16.a. from "below" to "above."

Response:

The Department does not believe a change is necessary since the word "below" refers to the Condition 16.b. that immediately follows Condition 16.a.

10. Section III. A. Condition 17 New Source Performance Standards for NOx

Comment:

Table 1 of 40 CFR 60, Subpart KKKK and Condition 17 specify the NO_x emission limitations in ppmvd @ 15% O_2 also Condition 32 specifies that the CEMS final results be expressed in ppmvd @ 15% O_2. However §60.4350(c) states, "Correction of measured NO_X concentrations to 15% O_2 is not allowed." This appears to be a conflicting requirement. Please clarify in the permit language whether the NO_X CEMS data should be corrected to 15% O_2 or not.

Response:

The Department acknowledges that correction of NO_X emissions concentrations to 15 percent oxygen (% O_2) is not allowed under the mentioned rule for the purposes of demonstrating compliance with that rule. Reliance upon the uncorrected NO_X concentrations as specified in the mentioned rule will actually decrease the theoretical NO_X emissions by a presently unknown value for the present project.

The Department will change all references to the NO_X limit throughout the permit to reflect that the allowable and measured concentrations are not and should not be corrected to 15% O_2. This will have the effect of reducing the potential to emit NO_X by several hundred tons per year.

Condition 17, Table Footnote b is modified as follows:

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks. Correction to 15% O_2 is not allowed consistent with the provisions of 40 CFR 60, Subpart KKKK.

11. Section III. A. Condition 18.d. Best Available Control Technology (BACT) Emissions Standards for CO and VOC

Comment:

As the project moves into combined cycle operation, PEF expects to run in simple cycle infrequently. Currently, FDEP requirements allow for a test waiver if liquid or solid fuel is burned for less than 400 hour per year, see Rule 62-297.310(7)(a)5, F.A.C. PEF is requesting similar language such that an annual compliance test could be waived if the unit did not operate in simple cycle mode for greater than 400 hours per year.

Response:

The Department acknowledges the comment; however no changes are needed. This section of Rule 62-297.310(7)(a)5, F.A.C. refers to particulate matter test and not to volatile organic compounds (VOC) or carbon monoxide (CO). These units are inherently very low emitters of particulate matter and are not subject to testing. Instead they are subject to visible emissions testing as surrogate for PM.

Rule 62-297.310(7)(a)5, F.A.C. states: "An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during start up, for a total of more than 400 hours."

12. Section III. A. Condition 20.c. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter) – Ammonia Slip

Comment:

Please add 40 CFR 63 Appendix A – Method 320 as an alternative test method for ammonia.

Response:

The Department agrees with the comment and Method 320 is added as an alternative method. Section III, Condition No. 20.c. is modified as follows:

c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Methods CTM-027 or 320.

The rest of this condition remains unchanged.

13. Section III. A. Condition 25. Allowable Data Exclusions

Comment:

Per the permit for PEF's Hines Energy Complex, the limitations and data exclusions are on a 24-hour block period. The current language does not specify 24-hour block average, though the BACT CEMS emission limitation is on a block average basis in Condition 18 and 24-hour block average is defined in Condition 32. Please change the language to reflect a 24-hour block average.

Response:

The Department believes that it is not necessary to modify this condition since the 24-hr block average is already defined and is a requisite of the BACT emission limits for the selected pollutant.

14. Section III. A. Condition 25.e. Allowable Data Exclusions - Fuel Switching

Comment:

The draft permit allows CEMs data exclusion of 2 hours per 24-hour period for fuel switching. Based on operating experience at PEF's Hines Energy Complex it has been observed that the Siemens F-Class CTs' fuel switch operation occurs at low loads in either fuel switch direction, which is different from the GE equivalent CTs. Also with recent increased hurricane activity, PEF has observed the need to be prepared to burn fuel oil in case of natural gas curtailment. The original equipment manufacturer of the Hines Energy Complex has recommended that a fuel switch be performed twice per month per CT. This enables the equipment associated with the fuel oil system to remain in working order and be ready for use during a possible curtailment.

PEF is requesting that the CEMs data exclusion for a fuel switch be 2 hours per fuel switch. However, PEF is not asking for a change to the limitation on the amount fuel oil burned.

Response:

The Department will need operating data from the manufacturer to consider this change. The Company can apply for a permit modification to address this issue after compiling the required data.

15. Section III. A. Condition 27 Test Methods

Comment:

Please add 40 CFR 63 Appendix A – Method 320 as an alternative test method.

Response:

The request is acceptable. The table in Condition 27 that lists test methods will be modified to reflect the additional procedure called "Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy".

16. Section III. A. Condition 31 CEMS Systems

Comment:

Please consider clarifying the language in the last sentence of the opening paragraph to note that the one working day excess emissions notification does not include excluded data. See the following: "CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO from the HRSG stacks and NO_X from all stacks in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions which after the application of Condition 25 (allowable data exclusions) are in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority."

Response:

The Department does not believe a change is necessary since the full conditions (25 and 31) as written are self explanatory. A revision in Item 18 below further clarifies the matter.

17. Section III. A. Condition 36.b. Fuel Sulfur Methods – Distillate Fuel Oil Sulfur Limit

Comment:

Please make the following change to the fuel sulfur analysis recordkeeping requirements: "b. Distillate Fuel Oil Sulfur Limit: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content."

Response:

The Department accepts the suggestion and modifies Section III.A. Condition 36.b as follows:

b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The rest of the condition remains unchanged.

18. Section III. A. Condition 38.b. Excess Emissions Reporting – SIP Quarterly Permit Limits Excess Emissions Reports

Comment:

See item 16 above regarding application of Condition 25 and excess emissions reporting. Please clarify the language in this condition as to the reporting of excess emissions that are outside the allowable data exclusion. Please consider the following: "SIP Quarterly Permit Limits Excess Emissions Report: Within 30 days following the end of each calendar-quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit and have not been excluded per Condition 25. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter."

Response:

The Department will not change Condition 38.b. as requested. However, the Department will clarify that excluded data should be provided with the Quarterly Report. This condition will be modified as follows:

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

The rest of the condition remains unchanged.

19. Section III. B. Emission Unit Description

Comment:

See item 2 above. The emission unit ID numbers are already assigned and should be changed.

Response:

See the Department's response to Comment No.2 above.

20. Section III. B. Condition 4. Equipment

Comment:

Please remove the last three words of Condition 4. The natural gas supply is for more than just the CTs. The suggested change is as follows: "Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply ~~to the CTs~~."

Response:

The Department accepts the suggestion and modifies Section III. B. Condition 4 as follows:

Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply ~~to the CTs~~. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

21. Section III. C and D. Emission Unit Description

Comment:

See item 2 above. The emission unit ID numbers are already assigned and should be changed.

Response:

See the Department's response to Comment No.2 above.

22. Section III. D. Condition 5. Authorized Fuel.

Comment:

The language listing the ASTM methods to be used for fuel sampling analysis should be changed to allow for future changes of the rules listing approved ASTM methods. Suggested change is as follows: "More recent versions of these methods or other Department approved methods may be used...."

Response:

The Department accepts the suggestion and modifies Section III. D. Condition 5 as follows:

Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content

CONCLUSION

The final action of the Department will be to issue the permit with the changes as noted above.

FACILITY AND PROJECT DESCRIPTION

Progress Energy Florida operates the Bartow Plant, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Three fossil fuel fired steam generating units designated as Units 1, 2 and 3 that produce 120, 120 and 225 megawatts (MW) of electrical power respectively;
- Four simple cycle units designated as Gas Combustion Turbine Peaking Units Nos. P-1, P-2, P-3 and P-4 each of which has a nominal capacity of 56 MW;
- Additional emissions units include a pipeline heating boiler and relocatable diesel generators; and
- Miscellaneous unregulated/insignificant emissions units and/or activities including fuel storage tanks and gas tanks that can be located at various PEF power plants. These units are listed in Appendix U of the current Title V Permit.

The project is a plant repowering that includes the construction of a nominal 1,280 MW gas-fired combined cycle unit system ("4-on-1") and a nominal 195 MW gas-fired simple cycle unit. The project includes and requires the shutdown of the three fossil fuel fired steam generating units (Units 1, 2 and 3) resulting in a net decrease in all PSD pollutants except for carbon monoxide (CO) and volatile organic compounds (VOC).

The combined cycle unit system will consist of: four Model SGT6-5000F combustion turbine-electrical generators (CT-electrical generators) with a nominal rating of 215 MW at ISO conditions when practicing power augmentation; four duct-fired heat recovery steam generators (HRSG's) each equipped with a selective catalytic reduction (SCR) reactor and a nominal 500 million Btu per hour (MMBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG). Each CT within the combined cycle unit system will be permitted to operate in simple cycle by directing the exhaust to a bypass stack instead of the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

All CTs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures and wet injection capability for nitrogen oxides control when firing fuel oil or when practicing power augmentation. Each CT will be allowed to fire backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). The new units are designated as Units 4 and Unit 5.

The simple cycle CT-electrical generator will have a nominal rating of 195 MW at ISO conditions and will exhaust through its own 120 foot stack.

Additional ancillary equipment will include: five natural gas fired fuel heaters; two diesel fuel storage tanks; one auxiliary steam boiler; and a diesel fueled emergency fire pump.

This permit authorizes the installation the following new equipment in conjunction with the permanent shutdown of Units 1, 2, and 3.

E.U. ID	Emission Unit Description
038	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
039	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
040	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
041	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
042	Unit 5 – One 195 MW (ISO) Combustion Turbine
043	One Nominal 85,000 lb/hr (99 MMBtu/hr) Auxiliary Boiler
044	Five Nominal 3 MMBtu/hr Gas-fired Process Heaters
045	Two Nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
046	One Nominal 300 horsepower Diesel-fueled Emergency Fire Pump

REGULATORY CLASSIFICATION

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources

The proposed project is subject to the following New Source Performance Standards of 40 CFR 60:

- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This rule also covers duct burners that are incorporated into combined cycle projects,
- Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boilers, and
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Title I, Section 112, Clean Air Act, National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The proposed project is subject to the following National Emissions Standards for Hazardous Air Pollutants:

- 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines.
- 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, or Institutional Boiler or Process Heater. Applies to auxiliary boiler and gas heaters.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD)

The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

Title IV, Clean Air Act, Acid Rain Provisions

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

Title V, Clean Air Act, Permits

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

Clean Air Interstate Rule (CAIR)

The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting)

The facility was not certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is not subject to Siting because there will be no net increase in steam-generated electrical power. [Design; Letter from Applicant Dated December 19, 2005]

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action:

- Air Construction Permit application received July 31, 2006;
- Department's Request for Additional Information dated August 30, 2006;
- Progress additional information received October 2 and October 26, 2006;
- Intent to Issue, Draft Air Construction Permit, and Technical Evaluation distributed December 13, 2006; and
- Final Determination distributed concurrently with Final Air Construction Permit.

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

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the Pinellas County Department of Environmental Management Office at 300 South Garden Avenue, Clearwater, Florida 34616.

3. Appendices: The following Appendices are attached as part of this permit: Appendix A (NSPS and NESHAP Subpart A – Identification of General Provisions); Appendix CF (Citation Format); Appendix GC (General Conditions); and Appendix CC (Common Conditions); Appendix IIII (NSPS Subpart IIII Provisions – Internal Combustion Engines); Appendix KKKK (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix YYYY (NESHAP Subpart YYYY Provisions – Combustion Turbines); Appendix BD (BACT Determination); Appendix DDDDD (NESHAP Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater); Appendix Dc (NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units); Appendix XS (Semiannual NSPS Excess Emissions Report).

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in general accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]

5. 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.]

6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. 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. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C. For good cause, the permittee may request that this PSD air construction permit be extended.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), 62-212.400(12)(a) and 62-212.400(10)(d), F.A.C.]

8. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]

9. 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. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]

10. 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 appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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(3), F.A.C.]

A. Combined Cycle Unit 4 and Simple Cycle Unit 5 (EU-038, 039, 040, 041 and 042)

This section of the permit addresses the following emissions unit.

E.U. ID	Emissions Units Comprising Combined Cycle Unit 4
038	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
039	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
040	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
041	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
042	Unit 5 – One 195 MW (ISO) Combustion Turbine

APPLICABLE STANDARDS AND REGULATIONS

1. PSD Applicability and BACT Determinations: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and Best Available Control Technology (BACT) determinations were made for carbon monoxide (CO) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rules 62-210.200 (Definitions) and 62-212.400, F.A.C.]

   {Permitting Note: The repowering project does not trigger PSD or require a BACT determination for NO_X, SO_2, sulfuric acid mist or PM/PM_{10} because emissions reductions from the permanent shutdown of existing fossil fueled steam generating Units 1, 2 and 3 will exceed emissions increases from the project by values greater than the respective significant emissions rates.}

2. NSPS Requirements: Each CT shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A - General Provisions*, including:

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

   b. *Subpart KKKK - Standards of Performance for Stationary Combustion Turbines:* These provisions were finalized on July 6, 2006 and include requirements applicable to duct burners located in HRSGs.

3. NESHAP Requirements: The CTs are subject to 40 CFR 63, Subpart A - Identification of General Provisions and 40 CFR 63, Subpart YYYY - National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines.

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines (CTs): The permittee is authorized to install, tune, operate, and maintain five Model SGT6-5000F CT-electrical generator sets. Each CT shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, evaporative inlet air-cooling system and a nominal 120 foot exhaust stack for simple cycle operation.
   [Application No. 1030011-010-AC; Design]

5. Heat Recovery Steam Generators (HRSGs): The permittee is authorized to install, operate, and maintain four new duct-fired HRSGs that recover exhaust heat energy from four of the CTs and deliver steam to a nominal 420 MW steam turbine electrical generator. Each HRSG shall be equipped with a nominal 120 foot

exhaust stack for combined cycle operation. [Application No. 1030011-010-AC; Design]

6. DLN Combustion: The permittee shall install, operate and maintain Dry Low NO_X (DLN) systems to control NO_X emissions from each CT when firing natural gas. Prior to the initial emissions performance tests required for each CT, the DLN combustors and automated combustion turbine control system shall be tuned without a selective catalytic reduction (SCR) system in operation to achieve the permitted CO, VOC and NO_X levels for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards.
[Application No. 1030011-010-AC; Design]

7. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each CT when firing distillate fuel oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without an SCR system in operation to achieve the NO_X value for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 1030011-010-AC; Design]

8. Selective Catalytic Reduction Systems: The permittee is authorized to install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use.
[Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

9. Oxidation Catalyst Systems: The permittee shall design and build the project to facilitate future installation of an oxidation catalyst system within each HRSG to control CO and VOC emissions from each of the four CTs/Duct-fired HRSGs comprising the combined cycle unit. The permittee may install oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 18.f. [Rule 62-4.070(3) F.A.C.]

10. Ammonia Storage: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Rule 62-4.070 F.A.C.]

PERFORMANCE RESTRICTIONS

11. Authorized Fuels: Each CT shall fire only natural gas and distillate oil. The maximum sulfur content of natural gas shall not exceed 2.0 grains of sulfur per 100 standard cubic feet of natural gas. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight.
[Design; Rules 62-4.070 and 62-210.200 (Definitions – PTE), F.A.C.; 40 CFR 60, Subpart KKKK]

12. Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the higher heating value (HHV) of each fuel, and 100% load. Heat input rates will vary depending upon CT characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(Definitions - PTE), F.A.C.]

13. Permitted Capacity - Duct Burners: The total nominal heat input rate to the duct burners (DBs) located within each HRSG is 500 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(Definitions - PTE), F.A.C.]

14. Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

    a. *Restriction on SC Operation*:

    - The combined operation of the two CTs shall not exceed 1,100 hours.
    - A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 operating days but not later than 60 calendar days after startup of the CTs.
    - Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period. Data recorded before and after CEMS certification shall be included in the calculation.
    - Each CT shall be stack tested to demonstrate initial compliance with the applicable Subpart KKKK NO_X emission standard for each fuel to be fired. 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. Data collected during the above described RATA may be used to satisfy this 60-day test requirement provided all requirements of 40 CFR 60.8 and Subpart KKKK are met.
    - The BACT emissions standards of specific condition 18 do not apply to these CTs prior to Unit 1, 2 and 3 shutdown. Following shutdown of Units 1, 2 and 3 all restrictions of this permit apply, including the BACT limits of specific condition 18.

    b. *Restriction on CC Operation*: No combined cycle operation of any unit is allowed prior to permanent shutdown of Units 1, 2, and 3.

    c. *Monthly Operations Summary*: By the 10th calendar day of each month, the permittee shall record the following in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, NO_X emissions in total tons for the month, and NO_X emissions in total tons for the described restricted period of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

    {Permitting note: The limitation on total NO_X emissions and adherence to the emissions standards in Specific Conditions 18, 19 and 20 along with the compliance and recordkeeping requirements of this condition will effectively ensure that emissions increases of all PSD pollutants from the selected CTs operated in SC mode prior to Unit 1, 2 and 3 shutdown will be less than their respective Significant Emissions Rates per Rule 62-210.200 (Definitions-SER), F.A.C.}

    [Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(12)(PSD Avoidance), F.A.C.; 40 CFR 60.8, and 40 CFR Subpart KKKK]

15. Restricted Operation: The permittee shall not exceed the following parameters following shutdown of Units 1, 2 and 3:
    a. The hours of operation of the CTs are not limited (8,760 hours per year).
    b. Distillate oil firing is limited to 1,000 hours per CT (i.e. 5,000 hours total aggregate for all five CTs) during any consecutive 12-month period.
    c. Operation of the DBs is limited to 2,434 hours per DB (i.e. 9,736 hours aggregate for four DBs) during any consecutive 12-month period.
    d. Power (steam) augmentation shall be limited to 1,688 hours per CT during any consecutive 12-month period.
    e. Other than startup, shutdown, fuel switching or documented malfunction the CTs shall operate above 70% load during simple cycle operation.
16. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTs may operate under the following methods of operation after shutdown of Units 1, 2 and 3
    a. *Simple Cycle (SC) Operation:* All five CTs may operate in simple cycle (SC) mode whereby the turbine exhaust gas (TEG) exits through or is diverted to a stack unassociated with a DB-fired HRSG. This method of operation will be an infrequent occurrence for the four CTs that will typically operate in combined cycle mode as described below.
    b. *Combined Cycle (CC) Operation*: The four CTs associated with combined cycle Unit 4 may operate in combined cycle (CC) mode whereby the TEG is exhausted to their respective duct-fired HRSGs for energy recovery in order to raise steam to drive the single steam turbine-electrical generator (STG) subject to the restrictions of this permit.
    c. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling systems may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.
    d. *Duct Firing*: The DB within each HRSG may be fired with natural gas to reheat the TEG in order to provide additional steam to the STG or the CTs for power augmentation.
    e. *Power augmentation:* Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the CT compressor discharge, thus increasing the power produced by the expander portion of the turbine.

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

EMISSIONS STANDARDS

17. New Source Performance Standards for NO_X: Emissions of NO_X shall not exceed the following emission limits for each CT or CT/DB-fired HRSG determined pursuant to 40 CFR 60, Subpart KKKK.

<table>
<tr><th>Pollutant</th><th>Fuel</th><th>Method of Operation [a]</th><th>CEMS [b] Rolling Average ppmvd (uncorrected)</th></tr>
<tr><td rowspan="5">NO_X [c]</td><td rowspan="2">Oil</td><td>CT (SC)</td><td>42 on 4-hour basis</td></tr>
<tr><td>CT (CC)</td><td>42 on 30-operating days basis</td></tr>
<tr><td rowspan="3">Gas</td><td>CT (SC)</td><td>15 on 4-hour basis</td></tr>
<tr><td>CT (CC)</td><td rowspan="2">15 on 30-operating days basis</td></tr>
<tr><td>CT & DB</td></tr>
</table>

a. CT (SC) means operation of CT in simple cycle mode. CT(CC) means operation of CT in combined cycle without use of the DB. CT & DB means operation in combined cycle mode and using the DB.

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks. Correction to 15% O_2 is not allowed consistent with the provisions of 40 CFR 60, Subpart KKKK.

c. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS.

Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

18. Best Available Control Technology (BACT) Emissions Standards for CO and VOC: Emissions of VOC and CO shall not exceed the following emission limits for each CT or CT/DB-fired HRSG.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

[Rule 62-210.200(Definitions – BACT) and 62-212.400 F.A.C.]

19. New Source Performance Standard for SO_2: Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input. Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

20. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter): The following measures and limitations, in conjunction with decreases from other units, effectively limit combined annual PM/PM_{10} emissions to a level that ensures net emissions increases are well below the significant emission rate at which PSD applies and a subsequent BACT determination is required. These measures also minimize fine particulate emissions and formation:

a. *Fuel Sulfur Limits*: The sulfur concentration shall be limited to 2 grains per 100 standard cubic feet of natural gas. The sulfur concentration in the distillate fuel oil used shall be limited to 0.05 percent. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content.

b. *Visible Emissions*: Visible emissions shall not exceed 10 percent opacity for each 6-minute block average. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.23

c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Methods TM-027 or 320.

[62-212.400(12)(PSD Avoidance)]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 18 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS or Acid Rain programs.}

21. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CTs, 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.]

22. 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.]

23. Definitions

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

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

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

24. 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.]

25. Allowable Data Exclusions: As per the procedures in this condition, limited amounts of CO CEMS emissions data may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C. For each CT/HRSG system, excess emissions resulting from startup, shutdown, and documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

    a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, up to 8 hours of excess emissions from any CT/HRSG system may be excluded in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, each CT/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

    b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, up to 3 hours in any 24-hour period of excess emissions from any CT/HRSG system can be excluded.

    c. *CT/HRSG System Cold Startup*: For cold startup of a CT/HRSG system, up to 4 hours in any 24-hour period can be excluded. "Cold startup of a CT/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

    d. *Simple Cycle CT Startup*: For startup of a CT for the purpose of operation in simple cycle mode, up to 1 hour in any 24-hour period of excess emissions can be excluded.

    e. *Fuel Switching*: For fuel switching, up to 2 hours in any 24-hour period can be excluded.

26. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 7 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

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

Method	Description of Method and Comments
CTM-027 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method.} The minimum detection limit shall be 1 ppm. Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) 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 Volatile Organic Concentrations

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]

28. Initial Compliance Determinations: Each CT shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, 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 configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Reference method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X compliance tests. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO mass rate emissions standards. CO and NO_X 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, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

29. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour and 12-month CO emission standards, and the NO_X 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. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

30. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CT shall be tested to demonstrate compliance with the emission standards for visible emissions. CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{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. The Department retains the right to require VOC testing for the reasons such as exceedance of the CO limit or those given in Appendix SC, Special Compliance Tests.}

[Rules 62-212.400, 62-210.200 (243) (BACT), 62-4.070 (3) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

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

    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

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

    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO is 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.

32. CEM Data Requirements:

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

- *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.
- *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]
- *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CO CEMS compliance demonstration subject to the provisions of Condition Nos. 25 and 26 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-4.070(3) and 62-212.400(12), F.A.C.; 40 CFR 75]

33. 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 by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the CT load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

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

35. Monthly Operations Summary: By the 10th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), 62-212.400, 62-210.200 (38) and 62-210.200 (243)(BACT), F.A.C.]

36. 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. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81. More recent versions of these methods or other Department approved methods may be used.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor or other fuel sulfur analysis performed on each delivery. 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.]

37. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

38. Excess Emissions Reporting:

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

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

c. *NSPS Semi-Annual Excess Emissions Reports*: Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions of the applicable NSPS that occurred during the previous semi-annual period.

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

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and Subpart KKKK]

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

B. Auxiliary Boiler and Process Heaters (EU-043 and 044)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
043	One Large Gaseous-fueled Auxiliary Boiler (99 MMBTU/hr and 85,000 lb/hr)
044	Five Small Gaseous-fueled Process Heaters (3 MMBtu/hr)

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

   [Rule 62-212.400, F.A.C.]

2. NESHAP Subpart DDDDD Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 63, Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

3. NSPS Subpart Dc Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

EQUIPMENT, CAPACITIES AND LIMITATIONS ON OPERATION

4. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of the limited use gas-fueled auxiliary boiler shall not exceed 1,000 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

EMISSIONS, FUELS AND TESTING REQUIREMENTS

6. Auxiliary Boiler Emissions Limits:

CO (BACT, Subpart DDDDD)	VOC (BACT)
0.08 lb/MMBtu, 400 ppmvd @3% O_2	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Dc; 40 CFR 63, Subpart DDDDD]

7. Auxiliary Boiler Testing Requirements: This unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. 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 combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

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

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

9. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

[40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

10. Natural Gas Fired Process Heaters Emissions Limits:

CO (BACT)	VOC (BACT)
0.08 lb/MMBtu	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

[Rule 62-212.400, F.A.C.]

11. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. 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 combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

[Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

12. Natural Gas Fired Process Heaters Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

13. Notification: Initial notification is required for the limited use 99 MMBtu/hr gas-fueled auxiliary boiler. Initial notification is not required for the five small gas-fueled 3 MMBtu/hr process heaters. [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

14. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

C. Distillate Fuel Oil Storage Tanks (EU-045)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
045	Two Nominal 3.5 million gallon distillate fuel oil storage tanks

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for volatile organic compounds (VOC) for these emissions units.

NSPS APPLICABILITY

2. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain two 3.5 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to the gas turbines. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

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

NOTIFICATION, REPORTING AND RECORDS

5. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report. [Rule 62-4.070(3) F.A.C]

6. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective Material Safety Data Sheets (MSDS) for the low sulfur fuel oil stored in the tanks. [Rule 62-4.070(3) and 62-212.400, F.A.C.]

D. Emergency Diesel Fire Pump (EU-046)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
046	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank.

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

2. NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines].

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) and an associated 500 gallon fuel oil storage tank.

4. Hours of Operation: The fire pump may operate in response to emergency conditions and 40 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.

EMISSIONS, FUELS AND TESTING REQUIREMENTS

5. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

6. Fire Pump Engine Emissions Limits:

   The following limits apply based on the size category of the fire pump located at the facility.

Size (hp)	CO (BACT, IIII)	NMHC*+NO_X (BACT for VOC, IIII)	PM
175 and greater	2.6 gm/bhp-hr	7.8 gm/bhp-hr	0.40

   Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

7. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

CONTENTS

CITATION FORMATS

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-317

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

"317" 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 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL PROVISIONS, SUBPART A FOR NSPS AND NESHAP

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

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

BACT DETERMINATION

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

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

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

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

Department's DRAFT BACT Summary for Auxiliary Boiler and Gas Heaters

The CO BACT limit for the fuel heaters and the auxiliary boiler is 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit is BACT for VOC.

Department's DRAFT BACT Summary for Emergency Fired Pump

The Department's BACT for the emergency fire pump (175 HP or greater) is compliance with the NSPS standards for CO and VOC and use of 0.05% sulfur fuel oil.

GENERAL CONDITIONS

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

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

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

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

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

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

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

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

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

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

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

13. This permit also constitutes:

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

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the 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. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

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

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

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

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

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

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

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

test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

19. <u>Records Retention</u>: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]
20. <u>Annual Operating Report</u>: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION 4. APPENDIX Dc

NSPS SUBPART Dc PROVISIONS

A 99 MMBTu/hr (85,000 lb/hr) auxiliary boiler will serve the combined cycle unit system to produce steam during start up of the CTs. The auxiliary boiler is regulated as Emissions Unit 043. The provisions of this Subpart may be provided in full upon request.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

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

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

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

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

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbines shall comply with the applicable federal requirements. These combustion gas turbines are regulated as Emissions Units 038, 039, 040, 041 and 042.

Source: Federal Register dated 7/6/06

The combustion gas turbines are subject to the applicable requirements of the 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request. These combustion gas turbines are regulated as Emissions Unit 038, 039, 040, 041 and 042.

Applicability of NESHAP Subpart YYYY

The Bartow Power Plant is a major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the West County Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

The auxiliary 99 MMBtu/hr boiler and the process heaters are subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. These emission units are regulated as E.U. 043 and 044 respectively. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

Tables to Subpart DDDDD of Part 63
Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD
Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

The emergency fired pump is subject to the applicable requirements of 40 CFR 60, Subpart IIII. This unit is regulated as emissions unit (E.U.) 046. The provisions of this Subpart may be provided in full upon request.

Source Federal Register Dated 7/11/06. EFECTIVE 9/11/06

Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers
60.4200 Am I subject to this subpart?

Emission Standards for Manufacturers
60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Emission Standards for Owners and Operators
60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators
60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators
60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?
60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements
60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators
60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators
60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Special Requirements
60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?
60.4216 What requirements must I meet for engines used in Alaska?

60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

General Provisions

60.4218 What parts of the General Provisions apply to me?

Definitions

60.4219 What definitions apply to this subpart?

Tables to Subpart IIII of Part 60

Table 1 to Subpart IIII of Part 60--Emission Standards for Stationary Pre-2007 Model Year Engines with a displacement of < 10 liters per cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and with a displacement of < 10 liters per cylinder

Table 2 to Subpart IIII of Part 60--Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE < 37 KW (50 HP) and with a Displacement of < 10 liters per cylinder

Table 3 to Subpart IIII of Part 60--Certification Requirements for Stationary Fire Pump Engines

Table 4 to Subpart IIII of Part 60--Emission Standards for Stationary Fire Pump Engines

Table 5 to Subpart IIII of Part 60--Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

Table 6 to Subpart IIII of Part 60--Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

Table 7 to Subpart IIII of Part 60--Requirements for Performance Tests for Stationary CI ICE with a displacement of >=30 liters per cylinder

Table 8 to Subpart IIII of Part 60--Applicability of General Provisions to Subpart IIII

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

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

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

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: ______________________

Process Unit(s) Description: ____

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

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

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

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

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

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

Name: ____

Signature: ____ *Date*: ____________________

Title: ____

Progress Energy

RECEIVED

JAN 03 2007

BUREAU OF AIR REGULATION

Via Overnight Delivery
January 2, 2007

Mr. A.A. Linero, 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: Proof of Publication – Public Notice
Draft Air Construction Permit Project No.: 1030011-010-AC/PSD-FL-381
Florida Power Corporation d/b/a Progress Energy Florida, Inc.
P.L. Bartow Plant
Facility ID 1030011
Bartow Plant Repowering Project

Dear Mr. Linero:

Please find enclosed a proof of publication for the public notice of intent to issue the air construction permit for the Bartow Plant Repowering Project at the Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF") P.L. Bartow Plant.

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

Sincerely,

Ann Quillian

Ann Quillian, PE
Senior Environmental Specialist
Environmental Services

Enclosure

cc: Rufus Jackson, PEF – P.L. Bartow Plant

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

1002212576

ST. PETERSBURG TIMES

Published Daily

St. Petersburg, Pinellas County, Florida

STATE OF FLORIDA
COUNTY OF PINELLAS } **S.S.**

Before the undersigned authority personally appeared **B. HARR** who on oath says that he/she is **Legal Clerk** of the ***St. Petersburg Times*** a daily newspaper published at St. Petersburg, in Pinellas County, Florida; that the attached copy of advertisement, being a **Legal Notice** in the matter **RE: DEP NOTICE OF INTENT TO ISSUE AIR PERMIT 1030011-010-AC PSD-FL-381** was published in said newspaper in the issues of **City & State , 12/13/06**

Affiant further says the said **ST. PETERSBURG TIMES** is a newspaper published at St. Petersburg, in said Pinellas County, Florida and that the said newspaper has heretofore been continuously published in said Pinellas County, Florida, each day and has been entered as second class mail matter at the post office in St. Petersburg, in said Pinellas County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement, and affiant further says that he /she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the pupose of securing this advertisement for publication in the said newspaper.

B. Harr

Signature of Affiant

Sworn to and subscribed before me
this **13th** day of **December A.D.2006**

Joseph F. Fish

Signature of Notary Public

Personally known X or produced indentification ___

Type of indentification produced ___

JOSEPH F FISH
MY COMMISSION #DD537744
EXPIRES: JUN 23, 2010
Bonded through 1st State Insurance

LEGAL NOTICE LE

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTI

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Power Corporation dba Progress Energy Florida, Inc.
P.L. Bartow Power Plant Repowering Project
Pinellas County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air cor
Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida (PEF). The permit is t
cycle unit and a natural gas-fueled simple cycle combustion turbine-electrical generator while permanen
steam electrical generating units at the P.L. Bartow Power Plant on Weedon Island in St. Petersburg, Pinellas
Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FA
and volatile organic compounds (VOC). The applicant corporate address is Florida Power Corporation dba
Avenue, St. Petersburg, Florida 33701.

The combined cycle unit will consist of: four Siemens SGT6-5000F gas-fueled combustion turbine-electr
combustors capable of operating in simple cycle or combined cycle modes; four duct-fired heat recove
turbine-electrical generator (STG); eight 120-feet exhaust stacks, i.e. two per CTG. Additional equipment
heaters; two nominal 3.5 million gallon storage tanks; and other associated support equipment.

The simple cycle unit will be a single Siemens SGT6-5000F gas-fueled CTG with a single stack. The combine
1,475 megawatts (MW) when referenced to standard (ISO) conditions. Approximately 420 MW of the total

The combined cycle unit and the simple cycle unit will each be permitted to operate continuously while fir
(0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five
each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam
year.

The boilers and stacks associated with existing residual oil-fired steam electrical generating Units 1, 2, an
units have STGs with a total capacity of approximately 472 MW. The installation of the combined cycle u
plant repowering project.

When firing natural gas, nitrogen oxides (NOX) emissions from all five CTGs will be limited to 15 parts pe
(ppmvd) as required by 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion
wet injection when using backup low sulfur (0.05%) fuel oil. The HRSGs within the combined cycle unit will
reduction (SCR) ammonia injection systems that provide PEF with the option of further controlling NOX to
Interstate Rule (CAIR).

The Department's proposed BACT CO emission limits for each of the five CGTs is 4.1 ppmvd when oper
operating on fuel oil. CO limits of 8.0 ppmvd on a 24-hour basis and 6 ppmvd on a 12-month basis als
operated in combined cycle mode. VOC emissions from all five CGTs will be limited to 1.2 and 2.8 ppmvd fo
CO and NOX will be continuously monitored when operating the HRSG exhaust stacks and NOX emissi
simple cycle stacks when in use. PEF has the option to install oxidation catalyst for CO and VOC control p
cycle operation is practiced.

There will be very substantial decreases in the regulated air pollutants except for CO and VOC. The maximu
units in tons per year are summarized below for comparison with recent annual emissions from the three u

Pollutants	Baseline Emissions Units 1,2,3	Future Emissions New Units	Net Increase
PM/PM10	804/559	413/413	(391/1
SAM	423	72	(351
SO2	24,818	466	(24,3
NOx	4,043	3,191	(852
VOC	57	145	88
CO	387	938	571

PEF may operate any two of the five CGTs in simple cycle mode prior to the permanent shutdown of Units 1
to 1,100 hours (aggregate) for the two CTGs, requires compliance with 40 CFR 60, Subpart KKKK, and ca
measured by CEMS. These conditions provide assurance that PSD will not be triggered during early operat

Ambient PSD impact analyses were required only for CO, but were also conducted for NOX, SO2, and PM1
scenarios. The modeling indicated that CO impacts will be less than the applicable Significant Impact Levels
NOX emissions will reduce ozone (smog) formation potential and nitrate fallout into local watersheds. The
will significantly reduce visible stack emissions, acid smut fallout, and fine particulate generation in the en
repowering project are all favorable and the net effect is a "creation of available increment."

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unles
the following procedures results in a different decision or significant change of terms or conditions. The
and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30
Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be p
Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail addres
filed shall be made available for public inspection. If the Department determines there is sufficient interest
of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a ne
affected by the permitting action. If comments received result in a significant change in the proposed agen
proposed permit and require, if applicable, another Public Notice.

The Department will issue the permit with the attached conditions unless a timely petition for an administr
120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hea
available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an
sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth be
in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, T
filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of rece
any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must
of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under se
asked the Department for notice of agency action may file a petition within fourteen days of receipt of thatno
A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time o
petition within the appropriate time period shall constitute a waiver of that person's right to request an ad
sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any s
approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Flori

A petition that disputes the material facts on which the Department's action is based must contain the follow
of each agency affected and each agency's file or identification number, if known; (b) The name, address, a
name, address, and telephone number of the petitioner's representative, if any, which shall be the address
the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the age
and when petitioner received notice of the agency action or proposed action; (d) A statement of all dispute
the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific fact
or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner
of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely
take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall st
otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C. Be
is designed to formulate final agency action, the filing of a petition means that the Department's final actio
by it in this notice. Persons whose substantial interests will be affected by any such final decision of the De
to petition to become a party to the proceeding, in accordance with the requirements set forth above.

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

Department of Environmental Protection	Department of Environmental Protection	Pinellas
Bureau of Air Regulation	Southwest District Office	Air Qual
111 S. Magnolia Drive, Suite 4	13501 N. Telecom Parkway	300 So
Tallahassee, Florida 32399-2400	Temple Terrace, Florida 33637-0926	Clearw
Telephone: 850/488-0114	Telephone: 813/632-7600	Telepho
Fax: 850/922-6979	Fax: 813/744-6084	Fax: 72

The complete project file includes the application, technical evaluations, Draft Permit, and the information s
exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the Program
at the Bureau of Air Regulation at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850
application, key correspondence, draft permit and technical evaluation can be accessed at http://www.d
bartow.htm

12/13/2006

1002212576

ST. PETERSBURG TIMES

Published Daily

St. Petersburg, Pinellas County, Florida

STATE OF FLORIDA
COUNTY OF PINELLAS } **S.S.**

Before the undersigned authority personally appeared **B. HARR** who on oath says that he/she is **Legal Clerk** of the ***St. Petersburg Times*** a daily newspaper published at St. Petersburg, in Pinellas County, Florida; that the attached copy of advertisement, being a **Legal Notice** in the matter **RE: DEP NOTICE OF INTENT TO ISSUE AIR PERMIT 1030011-010-AC PSD-FL-381** was published in said newspaper in the issues of **City & State , 12/13/06**

Affiant further says the said **ST. PETERSBURG TIMES** is a newspaper published at St. Petersburg, in said Pinellas County, Florida and that the said newspaper has heretofore been continuously published in said Pinellas County, Florida, each day and has been entered as second class mail matter at the post office in St. Petersburg, in said Pinellas County, Florida, for a period of one year next preceding the first publication of the attached copy of advertisement, and affiant further says that he /she has neither paid nor promised any person, firm or corporation any discount, rebate, commission or refund for the pupose of securing this advertisement for publication in the said newspaper.

B. Harr

Signature of Affiant

Sworn to and subscribed before me
this **13th** day of **December A.D.2006**

Joseph F. Fish

Signature of Notary Public

Personally known X or produced indentification ___

Type of indentification produced ________

JOSEPH F FISH
MY COMMISSION #DD537744
EXPIRES: JUN 23, 2010
Bonded through 1st State Insurance

LEGAL NOTICE LEGAL NOTICE

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Power Corporation dba Progress Energy Florida, Inc.
P.L. Bartow Power Plant Repowering Project
Pinellas County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the Rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida (PEF). The permit is to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle combustion turbine-electrical generator while permanently shutting down three residual oil-fueled steam electrical generating units at the P.L. Bartow Power Plant on Weedon Island in St. Petersburg, Pinellas County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The applicant corporate address is Florida Power Corporation dba Progress Energy Florida, Inc., 100 Central Avenue, St. Petersburg, Florida 33701.

The combined cycle unit will consist of: four Siemens SGT6-5000F gas-fueled combustion turbine-electrical generators (CTGs) with Dry Low NOX combustors capable of operating in simple cycle or combined cycle modes; four duct-fired heat recovery steam generators (HRSGs); one steam turbihe-electrical generator (STG); eight 120-feet exhaust stacks, i.e. two per CTG. Additional equipment includes: a small auxiliary boiler; five gas heaters; two nominal 3.5 million gallon storage tanks; and other associated support equipment.

The simple cycle unit will be a single Siemens SGT6-5000F gas-fueled CTG with a single stack. The combined capacity of the two units is approximately 1,475 megawatts (MW) when referenced to standard (ISO) conditions. Approximately 420 MW of the total will be from the new STG.

The combined cycle unit and the simple cycle unit will each be permitted to operate continuously while firing inherently clean natural gas. Low sulfur (0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five CTGs. The gas-fueled duct burner within each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam) augmentation mode for 1,688 hours per year.

The boilers and stacks associated with existing residual oil-fired steam electrical generating Units 1, 2, and 3 will be permanently shut down. These units have STGs with a total capacity of approximately 472 MW. The installation of the combined cycle unit and the simple cycle unit constitutes a plant repowering project.

When firing natural gas, nitrogen oxides (NOX) emissions from all five CTGs will be limited to 15 parts per million by volume at 15 percent oxygen (ppmvd) as required by 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. The NOX limit is 42 ppmvd by wet injection when using backup low sulfur (0.05%) fuel oil. The HRSGs within the combined cycle unit will be further equipped with selective catalytic reduction (SCR) ammonia injection systems that provide PEF with the option of further controlling NOX to generate allowances under the Clean Air Interstate Rule (CAIR).

The Department's proposed BACT CO emission limits for each of the five CGTs is 4.1 ppmvd when operating on natural gas and 8.0 ppmvd when operating on fuel oil. CO limits of 8.0 ppmvd on a 24-hour basis and 6 ppmvd on a 12-month basis also apply to the four CGT/HRSG sets when operated in combined cycle mode. VOC emissions from all five CGTs will be limited to 1.2 and 2.8 ppmvd for natural gas and fuel oil firing respectively. CO and NOX will be continuously monitored when operating the HRSG exhaust stacks and NOX emissions will be continuously monitored at the simple cycle stacks when in use. PEF has the option to install oxidation catalyst for CO and VOC control particularly if significant low load combined cycle operation is practiced.

There will be very substantial decreases in the regulated air pollutants except for CO and VOC. The maximum potential annual emissions from the new units in tons per year are summarized below for comparison with recent annual emissions from the three units slated for shut down.

Pollutants	Baseline Emissions Units 1,2,3	Future Emissions New Units	Net Increase (decrease)
PM/PM10	804/559	413/413	(391/146)
SAM	423	72	(351)
SO2	24,816	466	(24,350)
NOx	4,043	3,191	(852)
VOC	57	145	88
CO	367	938	571

PEF may operate any two of the five CGTs in simple cycle mode prior to the permanent shutdown of Units 1, 2 and 3. The permit limits this early mode to 1,100 hours (aggregate) for the two CTGs, requires compliance with 40 CFR 60, Subpart KKKK, and caps the emissions of NOX at 39 tons to be measured by CEMS. These conditions provide assurance that PSD will not be triggered during early operation of two CGTs.

Ambient PSD impact analyses were required only for CO, but were also conducted for NOX, SO2, and PM10 under the early and permanent operation scenarios. The modeling indicated that CO impacts will be less than the applicable Significant Impact Levels. Under the permanent scenario, the lower NOX emissions will reduce ozone (smog) formation potential and nitrate fallout into local watersheds. The lower PM/PM10, SO2 and SAM emissions will significantly reduce visible stack emissions, acid smut fallout, and fine particulate generation in the environment. The overall impacts due to the repowering project are all favorable and the net effect is a "creation of available increment."

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a newspaper of general circulation in the area affected by the permitting action. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of thatnotice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
13501 N. Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: 813/632-7600
Fax: 813/744-6084

Pinellas County DEM
Air Quality Division
300 South Garden Avenue
Clearwater, Florida 33756
Telephone: 727/464-4422
Fax: 727/464-4420

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

12/13/2006 212576-01

Adams, Patty

From: Quillian, Ann [Ann.Quillian@pgnmail.com]
Sent: Monday, December 18, 2006 8:12 AM
To: Harvey, Mary
Cc: Adams, Patty; Linero, Alvaro; Jackson, Rufus
Subject: RE: Bartow Documents #1030011-010-AC-DRAFT

Received your e-mail along with the five .pdf attachments. Thanks for your help.

Ann Q.

-----Original Message-----
From: Harvey, Mary [mailto:Mary.Harvey@dep.state.fl.us]
Sent: Friday, December 15, 2006 3:19 PM
To: Quillian, Ann
Cc: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

Ann, I have already emailed Rufus another copy earlier today. He has not responded back to me yet. I hope he received these documents.

Thanks,
Mary

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Friday, December 15, 2006 9:07 AM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Hessling, Peter A [mailto:phesslin@co.pinellas.fl.us]
Sent: Friday, December 15, 2006 7:31 AM
To: Harvey, Mary
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To: phesslin@co.pinellas.fl.us
Subject:

was read on 12/15/2006 7:31 AM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 5:37 PM
To: Adams, Patty; Linero, Alvaro
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

-----Original Message-----
From: Dee_Morse@nps.gov [mailto:Dee_Morse@nps.gov]
Sent: Thursday, December 14, 2006 4:47 PM
To: Harvey, Mary
Subject: Bartow Documents #1030011-010-AC-DRAFT

Return Receipt

Your document:	Bartow Documents #1030011-010-AC-DRAFT
was received by:	Dee Morse/DENVER/NPS
at:	12/14/2006 02:45:37 PM

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 5:37 PM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Nasca, Mara
Sent: Thursday, December 14, 2006 5:05 PM
To: Harvey, Mary
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To:	'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'
Cc:	Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject:	Bartow Documents #1030011-010-AC-DRAFT
Sent:	12/14/2006 4:24 PM

was read on 12/14/2006 5:05 PM.

Adams, Patty

From:	Harvey, Mary
Sent:	Thursday, December 14, 2006 5:36 PM
To:	Linero, Alvaro; Adams, Patty
Subject:	FW: Bartow Documents #1030011-010-AC-DRAFT
Attachments:	1030011.010.AC.D_pdf.zip

From: Nasca, Mara
Sent: Thursday, December 14, 2006 5:05 PM
To: Prickett, Patricia; Harvey, Mary
Cc: Zhang-Torres
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Harvey, Mary
Sent: Thursday, December 14, 2006 4:24 PM
To: 'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Bartow Documents #1030011-010-AC-DRAFT

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP, Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 4:31 PM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

From: Osbourn, Scott [mailto:Scott_Osbourn@golder.com]
Sent: Thursday, December 14, 2006 4:29 PM
Subject: Read: Bartow Documents #1030011-010-AC-DRAFT

Your message

To: Scott_Osbourn@golder.com
Subject:

was read on 12/14/2006 4:29 PM.

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 14, 2006 4:24 PM
To: 'rufus.jackson@pgnmail.com'; 'sosbourn@golder.com'; 'Ann.Quillian@pgnmail.com'; 'Dee_Morse@nps.gov'; 'meredith_bond@fws.gov'; 'Little.James@epamail.epa.gov'; Nasca, Mara; 'mayor@stpete.org'; 'sspratt@pinellascounty.org'; 'phesslin@pinellascounty.org'
Cc: Linero, Alvaro; Adams, Patty; Gibson, Victoria
Subject: Bartow Documents #1030011-010-AC-DRAFT
Attachments: 1030011.010.AC.D_pdf.zip

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,

DEP; Bureau of Air Regulation

Adams, Patty

From: Harvey, Mary
Sent: Thursday, December 21, 2006 10:31 AM
To: Adams, Patty
Subject: FW: Bartow Documents #1030011-010-AC-DRAFT

-----Original Message-----
From: Little.James@epamail.epa.gov [mailto:Little.James@epamail.epa.gov]
Sent: Wednesday, December 20, 2006 4:36 PM
To: Harvey, Mary
Subject: Re: Bartow Documents #1030011-010-AC-DRAFT

I received them. Thanks.

Jim

"Harvey, Mary" <Mary.Harvey@dep.state.fl.us>

12/15/2006 11:12 AM

To
James Little/R4/USEPA/US@EPA

cc
"Linero, Alvaro" <Alvaro.Linero@dep.state.fl.us>, "Adams, Patty" <Patty.Adams@dep.state.fl.us>

Subject
Bartow Documents #1030011-010-AC-DRAFT

As usual, we can not receive files with a .zip extension.

Jim Little - U.S. EPA Region 4
(404) 562-9118

Jim, I hope you got these files. Please email me back to let me know the if you received them this time.

Thanks,

Mary

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: http://www.adobe.com/products/acrobat/readstep.html.

The Bureau of Air Regulation is issuing electronic documents for permits, notices and other correspondence in lieu of hard copies through the United States Postal System, to provide greater service to the applicant and the engineering community. Please advise this office of any changes to your e-mail address or that of the Engineer-of-Record.

Thank you,
DEP, Bureau of Air Regulation

[attachment "APP381- #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "INTENT381 - #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "PERMIT381 - #1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US] [attachment "Signed Documents #1030011-010-AC - DRAFT.pdf" deleted by James Little/R4/USEPA/US] [attachment "TECHNICAL381 - 1030011-010-AC-DRAFT.PDF" deleted by James Little/R4/USEPA/US]

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

December 13, 2006

Electrically Sent – Received Receipt Requested

Mr. Rufus Jackson
Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 32701

Re: P.L. Bartow Plant Repowering Project
DEP File No.: 1030011-010-AC (PSD-FL-381)

Dear Mr. Jackson:

Enclosed are documents indicating the Department's preliminary determination to issue a permit pursuant to the rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida for the construction of a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit at the P.L. Bartow Plant located at 1601 Weedon Island Drive in St. Petersburg. The project includes and requires the shutdown of the three existing residual oil-fueled steam electrical generating units. The documents include: the Intent to Issue Air Construction Permit; the Public Notice of Intent to Issue Air Construction Permit; the Department's Technical Evaluation and Preliminary Determination including a draft determination of Best Available Control Technology; and the Draft Permit.

The <u>Public Notice</u> must be published one time only in a newspaper of general circulation in the area affected, pursuant to Chapter 50, Florida Statutes.

Please submit any other written comments you wish to have considered concerning the Department's proposed action to Mr. A. A. Linero, Program Administrator, South Permitting at the above letterhead address. If you have any questions, please call Debbie Nelson at 850/921-9537 (meteorologist), Teresa Heron at 850/921-9529 (review engineer) or Mr. Linero at 850/921-9523.

Sincerely,

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

AAL/th

Enclosures

reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

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

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

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Intent to Issue Air Construction Permit (including the Public Notice, Technical Evaluation, and the Draft Air Construction Permit) and all copies were sent electronically (with Received Receipt) before the close of business on 12/14/06 to the persons listed:

Rufus Jackson, PEF: rufus.jackson@pgnmail.com
Scott Osbourn, P.E., Golder: sosbourn@golder.com
Ann Quillian, P.E., PEF: ann.quillian@pgnmail.com
Dee Morse, NPS: dee_morse@nps.gov
Meredith Bond, U.S. FWS: meredith_bond@fws.gov
Jim Little, EPA: little.james@epa.gov
Mara Nasca, DEPSWD: mara.nasca@dep.state.fl.us
Mayor, City of St. Petersburg: mayor@stpete.org
Administrator, Pinellas County: sspratt@pinellascounty.org
Peter Hessling, PCDEM: phesslin@pinellascounty.org

Clerk Stamp

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

Mary L. Avery 12/14/06

(Clerk) (Date)

In the Matter of an
Application for Air Permit by:

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

DEP File No.: 1030011-010-AC
P.L. Bartow Power Plant
Repowering Project
Pinellas County

Authorized Representative: Mr. Rufus Jackson

INTENT TO ISSUE AIR CONSTRUCTION PERMIT

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

The applicant, Florida Power Corporation dba Progress Energy Florida, applied on July 31, 2006 to the Department for an air construction permit pursuant to the PSD rules to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle unit at the P.L. Bartow Power Plant on Weedon Island in Pinellas County. The project includes and requires the shutdown of three existing residual oil-fueled steam electrical generating units. The project is in effect a plant repowering.

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

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

Pursuant to Section 403.815, F.S., and Rule 62-110.106(7)(a)1., F.A.C., you (the applicant) are required to publish at your own expense the enclosed Public Notice of Intent to Issue Air Construction Permit (Notice). The notice shall be published one time only in the legal advertisement section of a newspaper of general circulation in the area affected. Rule 62-110.106(7)(b), F.A.C., requires that the applicant cause the Notice to be published as soon as possible after notification by the Department of its intended action. Pursuant to Rule 62-17.135(1)(c), F.A.C. the applicant shall have published in the appropriate newspapers the Notice no later than 10 days after the preliminary determination has been issued. For the purpose of these rules, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed below. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400 (Telephone: 850/488-0114; Fax 850/ 922-6979). You must provide proof of publication within seven days of publication, pursuant to Rule 62-110.106(5), F.A.C. No permitting action for which published notice is required shall be granted until proof of publication of notice is made by furnishing a uniform affidavit in substantially the form prescribed in section 50.051, F.S. to the office of the Department issuing the permit. Failure to publish the notice and provide proof of publication may result in the denial of the permit pursuant to Rules 62-110.106(9) & (11), F.A.C.

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

The Department will accept written comments and requests for public meetings concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of the enclosed Public Notice. Written comments and requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, Florida 32399-2400. Any written comments filed shall be made available for public inspection. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a newspaper of general circulation in the area affected by the permitting action. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

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

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

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Power Corporation dba Progress Energy Florida, Inc.
P.L. Bartow Power Plant Repowering Project
Pinellas County

The Department of Environmental Protection (Department) gives notice of its intent to issue an air construction permit under the Rules for the Prevention of Significant Deterioration of Air Quality (PSD) to Progress Energy Florida (PEF). The permit is to construct a natural gas-fueled combined cycle unit and a natural gas-fueled simple cycle combustion turbine-electrical generator while permanently shutting down three residual oil-fueled steam electrical generating units at the P.L. Bartow Power Plant on Weedon Island in St. Petersburg, Pinellas County. A determination of Best Available Control Technology (BACT) was required pursuant to Rule 62-212.400(6), Florida Administrative Code (FAC) for emissions of carbon monoxide (CO) and volatile organic compounds (VOC). The applicant's corporate address is Florida Power Corporation dba Progress Energy Florida, Inc., 100 Central Avenue, St. Petersburg, Florida 33701.

The combined cycle unit will consist of: four Siemens SGT6-5000F gas-fueled combustion turbine-electrical generators (CTGs) with Dry Low NO_X combustors capable of operating in simple cycle or combined cycle modes; four duct-fired heat recovery steam generators (HRSGs); one steam turbine-electrical generator (STG); eight 120-feet exhaust stacks, i.e. two per CTG. Additional equipment includes: a small auxiliary boiler; five gas heaters; two nominal 3.5 million gallon storage tanks; and other associated support equipment.

The simple cycle unit will be a single Siemens SGT6-5000F gas-fueled CTG with a single stack. The combined capacity of the two units is approximately 1,475 megawatts (MW) when referenced to standard (ISO) conditions. Approximately 420 MW of the total will be from the new STG.

The combined cycle unit and the simple cycle unit will each be permitted to operate continuously while firing inherently clean natural gas. Low sulfur (0.05 percent sulfur) distillate fuel oil will be allowed as backup fuel for 1000 hours per year per each of five CTGs. The gas-fueled duct burner within each of four HRSGs may operate 2,434 hours per year and each CTG may be operated in power (steam) augmentation mode for 1,688 hours per year.

The boilers and stacks associated with existing residual oil-fired steam electrical generating Units 1, 2, and 3 will be permanently shut down. These units have STGs with a total capacity of approximately 472 MW. The installation of the combined cycle unit and the simple cycle unit constitutes a plant repowering project.

When firing natural gas, nitrogen oxides (NO_X) emissions from all five CTGs will be limited to 15 parts per million by volume at 15 percent oxygen (ppmvd) as required by 40 CFR 60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. The NO_X limit is 42 ppmvd by wet injection when using backup low sulfur (0.05%) fuel oil. The HRSGs within the combined cycle unit will be further equipped with selective catalytic reduction (SCR) ammonia injection systems that provide PEF with the option of further controlling NO_X to generate allowances under the Clean Air Interstate Rule (CAIR).

The Department's proposed BACT CO emission limits for each of the five CGTs is 4.1 ppmvd when operating on natural gas and 8.0 ppmvd when operating on fuel oil. CO limits of 8.0 ppmvd on a 24-hour basis and 6 ppmvd on a 12-month basis also apply to the four CGT/HRSG sets when operated in combined cycle mode. VOC emissions from all five CGTs will be limited to 1.2 and 2.8 ppmvd for natural gas and fuel oil firing respectively. CO and NO_X will be continuously monitored when operating the HRSG exhaust stacks and NO_X emissions will be continuously monitored at the simple cycle stacks when in use. PEF has the option to install oxidation catalyst for CO and VOC control particularly if significant low load combined cycle operation is practiced.

There will be very substantial decreases in the regulated air pollutants except for CO and VOC. The maximum potential annual emissions from the new units in tons per year are summarized below for comparison with recent annual emissions from the three units slated for shut down.

Pollutants	Baseline Emissions Units 1,2, 3	Future Emissions New Units	Net Increase (decrease)
PM/PM_{10}	804/559	413/413	(391/146)
SAM	423	72	(351)
SO_2	24,816	466	(24,350)
NO_x	4,043	3,191	(852)
VOC	57	145	88
CO	367	938	571

PEF may operate any two of the five CGTs in simple cycle mode prior to the permanent shutdown of Units 1, 2 and 3. The permit limits this early mode to 1,100 hours (aggregate) for the two CTGs, requires compliance with 40 CFR 60, Subpart KKKK, and caps the emissions of NO_X at 39 tons to be measured by CEMS. These conditions provide assurance that PSD will not be triggered during early operation of two CGTs.

Ambient PSD impact analyses were required only for CO, but were also conducted for NO_X, SO_2, and PM_{10} under the early and permanent operation scenarios. The modeling indicated that CO impacts will be less than the applicable Significant Impact Levels.

(Public Notice to be Published in the Newspaper)

Under the permanent scenario, the lower NO_X emissions will reduce ozone (smog) formation potential and nitrate fallout into local watersheds. The lower PM/PM_{10}, SO_2 and SAM emissions will significantly reduce visible stack emissions, acid smut fallout, and fine particulate generation in the environment. The overall impacts due to the repowering project are all favorable and the net effect is a "creation of available increment."

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions. The Department will accept written comments and requests for a public meeting concerning the proposed permit issuance action for a period of thirty (30) days from the date of publication of this Public Notice of Intent to Issue PSD Permit. Written comments or requests for public meetings should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400 or the e-mail address provided below. Any written comments filed shall be made available for public inspection. If the Department determines there is sufficient interest for a public meeting, it will publish notice of the time, date, and location in the Florida Administrative Weekly at http://faw.dos.state.fl.us and in a newspaper of general circulation in the area affected by the permitting action. If comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice.

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

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen (14) days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

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

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32399-2400
Telephone: 850/488-0114
Fax: 850/922-6979

Department of Environmental Protection
Southwest District Office
13501 N, Telecom Parkway
Temple Terrace, Florida 33637-0926
Telephone: 813/632-7600
Fax: 813/744-6084

Pinellas County DEM
Air Quality Division
300 South Garden Avenue
Clearwater, Florida 33756
Telephone: 727/464-4422
Fax: 727/464-4420

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

(Public Notice to be Published in the Newspaper)

DRAFT PERMIT

PERMITTEE

Florida Power Corporation dba
Progress Energy Florida, Inc.
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Mr. Rufus Jackson

DEP File No. 1030011-010-AC Permit No. PSD-FL-381 PEF P.L. Bartow Power Plant Plant Repowering Project Pinellas County SIC No. 4911 Expires: March 31, 2010

PROJECT AND LOCATION

This permit authorizes the construction of one nominal 1,280 megawatt (MW) combined cycle unit and one nominal 195 MW simple cycle unit at the Progress Energy Florida (PEF) P.L. Bartow Power Plant located at 1601 Weedon Island Drive, St. Petersburg, Pinellas County.

Three existing fossil fuel fired steam generators designated as Units 1, 2 and 3 with a total nominal capacity of 465 MW will be shut down as part of this project.

The UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

STATEMENT OF BASIS

This 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.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations. The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

CONTENTS

(DRAFT)

__________________________ __________
Joseph Kahn, Director (Date)
Division of Air Resource
Management

FACILITY AND PROJECT DESCRIPTION

Progress Energy Florida operates the Bartow Plant, which is an existing power plant (SIC No. 4911). The plant currently consists of:

- Three fossil fuel fired steam generating units designated as Units 1, 2 and 3 that produce 120, 120 and 225 megawatts (MW) of electrical power respectively;
- Four simple cycle units designated as Gas Combustion Turbine Peaking Units Nos. P-1, P-2, P-3 and P-4 each of which has a nominal capacity of 56 MW; and
- Miscellaneous unregulated/insignificant emissions units including a pipeline heating boiler and relocatable diesel generators that can be located at various PEF power plants.

The project is a plant repowering that includes the construction of a nominal 1,280 MW gas-fired combined cycle unit system ("4-on-1") and a nominal 195 MW gas-fired simple cycle unit. The project includes and requires the shutdown of the three fossil fuel fired steam generating units (Units 1, 2 and 3) resulting in a net decrease in all PSD pollutants except for carbon monoxide (CO) and volatile organic compounds (VOC).

The combined cycle unit system will consist of: four Model SGT6-5000F combustion turbine-electrical generators (CT-electrical generators) with a nominal rating of 215 MW at ISO conditions when practicing power augmentation; four duct-fired heat recovery steam generators (HRSG's) each equipped with a selective catalytic reduction (SCR) reactor and a nominal 500 million Btu per hour (MMBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG). Each CT within the combined cycle unit system will be permitted to operate in simple cycle by directing the exhaust to a bypass stack instead of the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

All CTs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures and wet injection capability for nitrogen oxides control when firing fuel oil or when practicing power augmentation. Each CT will be allowed to fire backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). The new units are designated as Units 4 and Unit 5.

The simple cycle CT-electrical generator will have a nominal rating of 195 MW at ISO conditions and will exhaust through its own 120 foot stack.

Additional ancillary equipment will include: five natural gas fired fuel heaters; two diesel fuel storage tanks; one auxiliary steam boiler; and a diesel fueled emergency fire pump.

This permit authorizes the installation the following new equipment in conjunction with the permanent shutdown of Units 1, 2, and 3.

E.U. ID	Emission Unit Description
009	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
010	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
011	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
012	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
013	Unit 5 – One 195 MW (ISO) Combustion Turbine
014	One Nominal 85,000 lb/hr (99 MMBtu/hr) Auxiliary Boiler
015	Five Nominal 3 MMBtu/hr Gas-fired Process Heaters
016	Two Nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
017	One Nominal 300 horsepower Diesel-fueled Emergency Fire Pump

REGULATORY CLASSIFICATION

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources

The proposed project is subject to the following New Source Performance Standards of 40 CFR 60:

- Subpart KKKK - Standards of Performance for Stationary Combustion Turbines. This rule also covers duct burners that are incorporated into combined cycle projects,
- Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boilers, and
- Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Title I, Section 112, Clean Air Act, National Emissions Standards for Hazardous Air Pollutants (NESHAP)

The proposed project is subject to the following National Emissions Standards for Hazardous Air Pollutants:

- 40 CFR 63, Subpart YYYY – NESHAP for Stationary Combustion Turbines.
- 40 CFR 63, Subpart DDDDD – NESHAP for Industrial, Commercial, or Institutional Boiler or Process Heater. Applies to auxiliary boiler and gas heaters.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD)

The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

Title IV, Clean Air Act, Acid Rain Provisions

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

Title V, Clean Air Act, Permits

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

Clean Air Interstate Rule (CAIR)

The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting)

The facility was not certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is not subject to Siting because there will be no net increase in steam-generated electrical power. [Design; Letter from Applicant Dated December 19, 2005]

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action:

- Air Construction Permit application received July 31, 2006;
- Department's Request for Additional Information dated August 30, 2006;
- Progress additional information received October 2 and October 26, 2006;
- Intent to Issue, Draft Air Construction Permit, and Technical Evaluation distributed December 13, 2006; and
- Final Determination distributed concurrently with Final Air Construction Permit.

1. Permitting Authority: All documents related to applications for permits to construct, modify, or operate emissions units at this facility shall be submitted to the Bureau of Air Regulation of the Florida Department of Environmental Protection (DEP) at 2600 Blair Stone Road (MS #5505), Tallahassee, Florida 32399-2400. Copies of all such related documents shall also be submitted to the Compliance Authority.
2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Air Quality Division of the Pinellas County Department of Environmental Management Office at 300 South Garden Avenue, Clearwater, Florida 34616.
3. Appendices: The following Appendices are attached as part of this permit: Appendix A (NSPS and NESHAP Subpart A – Identification of General Provisions); Appendix CF (Citation Format); Appendix GC (General Conditions); and Appendix CC (Common Conditions); Appendix IIII (NSPS Subpart IIII Provisions – Internal Combustion Engines); Appendix KKKK (NSPS Subpart KKKK Provisions - Combustion Turbines and Duct Burners); Appendix YYYY (NESHAP Subpart YYYY Provisions – Combustion Turbines); Appendix BD (BACT Determination); Appendix DDDDD (NESHAP Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater); Appendix Dc (NSPS Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units); Appendix XS (Semiannual NSPS Excess Emissions Report).
4. Applicable Regulations, Forms and Application Procedures: Unless otherwise indicated in this permit, the construction and operation of the subject emissions unit shall be in general accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403 of the Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.); and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR), adopted by reference in Rule 62-204.800, F.A.C. The terms used in this permit have specific meanings as defined in the applicable chapters of the Florida Administrative Code. The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations. [Rules 62-204.800, 62-210.300 and 62-210.900, F.A.C.]
5. 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.]
6. Modifications: The permittee shall notify the Compliance Authority upon commencement of construction. 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. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]
7. 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. Authorization to construct shall expire if construction is not commenced within 18 months after receipt of the permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. This provision does not apply to the time period between construction of the approved phases of a phased construction project except that each phase must commence construction within 18 months of the commencement date established by the Department in the permit. The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C. For good cause, the permittee may request that this PSD air construction permit be extended.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), 62-212.400(12)(a) and 62-212.400(10)(d), F.A.C.]

8. Source Obligation: At such time that a particular source or modification becomes a major stationary source or major modification (as these terms were defined at the time the source obtained the enforceable limitation) solely by virtue of a relaxation in any enforceable limitation which was established after August 7, 1980, on the capacity of the source or modification otherwise to emit a pollutant, such as a restriction on hours of operation, then the requirements of subsections 62-212.400(4) through (12), F.A.C., shall apply to the source or modification as though construction had not yet commenced on the source or modification. [Rule 62-212.400(12)(b), F.A.C.]
9. 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. This permit does not specify the Acid Rain program requirements. These will be included in the Title V air operation permit. [40 CFR 72]
10. 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 appropriate Permitting Authority with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]
11. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours 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(3), F.A.C.]

A. Combined Cycle Unit 4 and Simple Cycle Unit 5 (EU-009, 010, 011, 012 and 013)

This section of the permit addresses the following emissions unit.

E.U. ID	Emissions Units Comprising Combined Cycle Unit 4
009	Unit 4A – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
010	Unit 4B – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
011	Unit 4C – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
012	Unit 4D – One 215 MW (ISO) Combustion Turbine with Duct-fired Heat Recovery Steam Generator
013	Unit 5 – One 195 MW (ISO) Combustion Turbine

APPLICABLE STANDARDS AND REGULATIONS

1. PSD Applicability and BACT Determinations: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and Best Available Control Technology (BACT) determinations were made for carbon monoxide (CO) and volatile organic compounds (VOC).

   See Appendix BD of this permit for a summary of the final BACT determinations.
   [Rules 62-210.200 (Definitions) and 62-212.400, F.A.C.]

   {Permitting Note: The repowering project does not trigger PSD or require a BACT determination for NO_X, SO_2, sulfuric acid mist or PM/PM_{10} because emissions reductions from the permanent shutdown of existing fossil fueled steam generating Units 1, 2 and 3 will exceed emissions increases from the project by values greater than the respective significant emissions rates.}

2. NSPS Requirements: Each CT shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

   a. *Subpart A - General Provisions*, including:

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

   b. *Subpart KKKK - Standards of Performance for Stationary Combustion Turbines:* These provisions were finalized on July 6, 2006 and include requirements applicable to duct burners located in HRSGs.

3. NESHAP Requirements: The CTs are subject to 40 CFR 63, Subpart A - Identification of General Provisions and 40 CFR 63, Subpart YYYY - National Emissions Standard for Hazardous Air Pollutants for Stationary Combustion Turbines.

EQUIPMENT AND CONTROL TECHNOLOGY

4. Combustion Turbines (CTs): The permittee is authorized to install, tune, operate, and maintain five Model SGT6-5000F CT-electrical generator sets. Each CT shall include an automated control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, evaporative inlet air-cooling system and a nominal 120 foot exhaust stack for simple cycle operation.
   [Application No. 1030011-010-AC; Design]

5. Heat Recovery Steam Generators (HRSGs): The permittee is authorized to install, operate, and maintain four new duct-fired HRSGs that recover exhaust heat energy from four of the CTs and deliver steam to a nominal 420 MW steam turbine electrical generator. Each HRSG shall be equipped with a nominal 120 foot

exhaust stack for combined cycle operation. [Application No. 1030011-010-AC; Design]

6. DLN Combustion: The permittee shall install, operate and maintain Dry Low NO_X (DLN) systems to control NO_X emissions from each CT when firing natural gas. Prior to the initial emissions performance tests required for each CT, the DLN combustors and automated combustion turbine control system shall be tuned without a selective catalytic reduction (SCR) system in operation to achieve the permitted CO, VOC and NO_X levels for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards.
[Application No. 1030011-010-AC; Design]

7. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NO_X emissions from each CT when firing distillate fuel oil. Prior to the initial emissions performance tests, the water injection system shall be tuned without an SCR system in operation to achieve the NO_X value for simple cycle operation. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations or industry standards. [Application No. 1030011-010-AC; Design]

8. Selective Catalytic Reduction Systems: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system within each HRSG to control NO_X emissions from each of the four CT/Duct-fired HRSGs comprising the combined cycle unit. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. Operation of the SCR systems is not required when the NO_X emission limits can be met without their use.
[Application No. 1030011-010-AC; Design, and 62-210.650 (Circumvention), F.A.C.]

9. Oxidation Catalyst Systems: The permittee shall design and build the project to facilitate future installation of an oxidation catalyst system within each HRSG to control CO and VOC emissions from each of the four CTs/Duct-fired HRSGs comprising the combined cycle unit. The permittee may install oxidation catalyst during project construction or, after notifying the Department, at a future date as described in Specific Condition 18.f. [Rule 62-4.070(3) F.A.C.]

10. Ammonia Storage: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68.
[Rule 62-4.070 F.A.C.]

PERFORMANCE RESTRICTIONS

11. Authorized Fuels: Each CT shall fire only natural gas and distillate oil. The maximum sulfur content of natural gas shall not exceed 2.0 grains of sulfur per 100 standard cubic feet of natural gas. The maximum sulfur content of distillate oil shall not exceed 0.05% by weight.
[Design; Rules 62-4.070 and 62-210.200 (Definitions – PTE), F.A.C.; 40 CFR 60, Subpart KKKK]

12. Permitted Capacity - Combustion Turbines: The nominal heat input rate excluding steam for power augmentation to each CT is 1,972 MMBtu per hour when firing natural gas and 1,876 MMBtu per hour when firing distillate fuel oil based on a compressor inlet air temperature of 59° F, the lower heating value (HHV) of each fuel, and 100% load). Heat input rates will vary depending upon CT characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(Definitions - PTE), F.A.C.]

13. Permitted Capacity - Duct Burners: The total nominal heat input rate to the duct burners (DBs) located within each HRSG is 500 MMBtu per hour based on the higher heating value (HHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(Definitions - PTE), F.A.C.]

14. Temporary Simple Cycle Operation of Two CTs Prior to Permanent Shutdown of Units 1, 2 and 3: The permittee may select any two of the five new CTs to be operated as simple cycle units prior to shutdown of Units 1, 2 and 3. The restrictions included in this condition apply only to those CTs chosen, and only during the described period. Once selected, only those CTs chosen may be operated prior to shutdown of Units 1, 2 and 3 in accordance with the following restrictions:

   a. *Restriction on SC Operation*:

      - The combined operation of the two CTs shall not exceed 1,100 hours.
      - A NO_X CEMS shall be installed and operating in each stack prior to startup of the CTs in order to collect and record data for the purpose of demonstrating compliance with this requirement. Notwithstanding the relative accuracy test audit (RATA) grace period described in 40 CFR 75 Appendix B, the NO_X CEMS shall be fully certified in accordance with the requirements of 40 CFR 75 (including a RATA), within 30 calendar days of startup of the CTs.
      - Total emissions of NO_X from the two CTs shall not exceed 39 tons during all operation including startups, shutdowns and malfunctions as measured and recorded by the required NO_X continuous emissions monitoring systems (CEMS) during the temporary period.
      - Each CT shall be stack tested to demonstrate initial compliance with the applicable Subpart KKKK NO_X emission standard for each fuel to be fired. 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. Data collected during the above described RATA may be used to satisfy this 60-day test requirement provided all requirements of 40 CFR 60.8 and Subpart KKKK are met.
      - The BACT emissions standards of specific condition 18 do not apply to these CTs prior to Unit 1, 2 and 3 shutdown. Following shutdown of Units 1, 2 and 3 all restrictions of this permit apply, including the BACT limits of specific condition 18.

   b. *Restriction on CC Operation*: No combined cycle operation of any unit is allowed prior to permanent shutdown of Units 1, 2, and 3.

   c. *Monthly Operations Summary*: By the 10^{th} calendar day of each month, the permittee shall record the following in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, NO_X emissions in total tons for the month, and NO_X emissions in total tons for the described restricted period of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

{Permitting note: The limitation on total NO_X emissions and adherence to the emissions standards in Specific Conditions 18, 19 and 20 along with the compliance and recordkeeping requirements of this condition will effectively ensure that emissions increases of all PSD pollutants from the selected CTs operated in SC mode prior to Unit 1, 2 and 3 shutdown will be less than their respective Significant Emissions Rates per Rule 62-210.200 (Definitions-SER), F.A.C.}

[Rules 62-4.070(3), 62-210.200(PTE) and 62-212.400(12)(PSD Avoidance), F.A.C.; 40 CFR 60.8, and 40 CFR Subpart KKKK]

15. Restricted Operation: The permittee shall not exceed the following parameters following shutdown of Units 1, 2 and 3:
    a. The hours of operation of the CTs are not limited (8,760 hours per year).
    b. Distillate oil firing is limited to 1,000 hours per CT (i.e. 5,000 hours total aggregate for all five CTs) during any consecutive 12-month period.
    c. Operation of the DBs is limited to 2,434 hours per DB (i.e. 9,736 hours aggregate for four DBs) during any consecutive 12-month period.
    d. Power (steam) augmentation shall be limited to 1,688 hours per CT during any consecutive 12-month period.
    e. Other than startup, shutdown, fuel switching or documented malfunction the CTs shall operate above 70% load during simple cycle operation.
16. Methods of Operation: Subject to the restrictions and requirements of this permit, the CTs may operate under the following methods of operation after shutdown of Units 1, 2 and 3
    a. *Simple Cycle (SC) Operation:* All five CTs may operate in simple cycle (SC) mode whereby the turbine exhaust gas (TEG) exits through or is diverted to a stack unassociated with a DB-fired HRSG. This method of operation will be an infrequent occurrence for the four CTs that will typically operate in combined cycle mode as described below.
    b. *Combined Cycle (CC) Operation*: The four CTs associated with combined cycle Unit 4 may operate in combined cycle (CC) mode whereby the TEG is exhausted to their respective duct-fired HRSGs for energy recovery in order to raise steam to drive the single steam turbine-electrical generator (STG) subject to the restrictions of this permit.
    c. *Inlet Conditioning*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling systems may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power.
    d. *Duct Firing*: The DB within each HRSG may be fired with natural gas to reheat the TEG in order to provide additional steam to the STG or the CTs for power augmentation.
    e. *Power augmentation:* Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the CT compressor discharge, thus increasing the power produced by the expander portion of the turbine.

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

EMISSIONS STANDARDS

17. New Source Performance Standards for NO_X: Emissions of NO_X shall not exceed the following emission limits for each CT or CT/DB-fired HRSG determined pursuant to 40 CFR 60, Subpart KKKK.

Pollutant	Fuel	Method of Operation [a]	CEMS [b] Rolling Average ppmvd @ 15% O_2
NO_X [c]	Oil	CT (SC)	42 on 4-hour basis
		CT (CC)	42 on 30-operating days basis
	Gas	CT (SC)	15 on 4-hour basis
		CT (CC)	15 on 30-operating days basis
		CT & DB	

a. CT (SC) means operation of CT in simple cycle mode. CT(CC) means operation of CT in combined cycle without use of the DB. CT & DB means operation in combined cycle mode and using the DB.

b. A CEMS for NO_X shall be installed on the CT stacks and on the HRSG stacks.

c. Compliance with the continuous NO_X standards shall be demonstrated based on data collected by the required CEMS.

Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

18. Best Available Control Technology (BACT) Emissions Standards for CO and VOC: Emissions of VOC and CO shall not exceed the following emission limits for each CT or CT/DB-fired HRSG.

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

[Rule 62-210.200(Definitions – BACT) and 62-212.400 F.A.C.]

19. New Source Performance Standard for SO_2: Pursuant to §60.4330(a)(2), SO_2 emissions are limited in NSPS Subpart KKKK by a prohibition on the firing of any fuels that contain total potential sulfur emissions in excess of 0.060 lb SO_2/MMBtu heat input.. Refer to Appendix KKKK of this permit for the full NSPS requirements. [40 CFR 60, Subpart KKKK]

20. Measures to Limit Particulate Emissions (PM/PM_{10}/Fine Particulate Matter): The following measures and limitations, in conjunction with decreases from other units, effectively limit combined annual PM/PM_{10} emissions to a level that ensures net emissions increases are well below the significant emission rate at which PSD applies and a subsequent BACT determination is required. These measures also minimize fine particulate emissions and formation:

    a. *Fuel Sulfur Limits*: The sulfur concentration shall be limited to 2 grains per 100 standard cubic feet of natural gas. The sulfur concentration in the distillate fuel oil used shall be limited to 0.05 percent. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content.

    b. *Visible Emissions*: Visible emissions shall not exceed 10 percent opacity for each 6-minute block average. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

    c. *Ammonia Emissions (Slip) Limits*: Ammonia emissions shall be limited to 5 ppmvd @15% O_2. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027.

    [62-212.400(12)(PSD Avoidance)]

EXCESS EMISSIONS

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 18 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS or Acid Rain programs.}

21. Operating Procedures: The Best Available Control Technology (BACT) determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and maintain the CTs, 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.]

22. 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.]

23. Definitions

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

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

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

24. 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.]

25. Allowable Data Exclusions: As per the procedures in this condition, limited amounts of CO CEMS emissions data may be excluded from the corresponding SIP-based compliance demonstration, provided that best operational practices to minimize emissions are adhered to and the duration of data excluded is minimized. As provided by the authority in Rule 62-210.700(5), F.A.C., these conditions replace the provisions in Rule 62-210.700(1), F.A.C. For each CT/HRSG system, excess emissions resulting from startup, shutdown, and documented malfunctions shall not exceed two hours in any 24-hour period except for the specific cases listed below. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

   a. *Steam Turbine/HRSG System Cold Startup*: For cold startup of the steam turbine system, up to 8 hours of excess emissions from any CT/HRSG system may be excluded in any 24-hour period. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

   {Permitting Note: During a cold startup of the steam turbine system, each CT/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}

   b. *Shutdown Combined Cycle Operation*: For shutdown of the combined cycle operation, up to 3 hours in any 24-hour period of excess emissions from any CT/HRSG system can be excluded.

   c. *CT/HRSG System Cold Startup*: For cold startup of a CT/HRSG system, up to 4 hours in any 24-hour period can be excluded. "Cold startup of a CT/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

   d. *Simple Cycle CT Startup*: For startup of a CT for the purpose of operation in simple cycle mode, up to 1 hour in any 24-hour period of excess emissions can be excluded.

   e. *Fuel Switching*: For fuel switching, up to 2 hours in any 24-hour period can be excluded.

26. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 7 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.
[Design; Rule 62-4.070(3), F.A.C.]

EMISSIONS PERFORMANCE TESTING

27. 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 Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) 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 Volatile Organic Concentrations

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]

28. Initial Compliance Determinations: Each CT shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, 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 configuration. Each unit shall be tested when firing natural gas, when using the duct burners and when firing distillate fuel oil. Reference method data collected during the required Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the initial CO and NO_X compliance tests. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO mass rate emissions standards. CO and NO_X 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, oxidation catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

29. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour and 12-month CO emission standards, and the NO_X 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. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion and oxidation catalyst operation, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

30. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each CT shall be tested to demonstrate compliance with the emission standards for visible emissions. CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate compliance with the CO standards. Annual testing to determine the ammonia slip shall be conducted while firing the primary fuel. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run.

{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. The Department retains the right to require VOC testing for the reasons such as exceedance of the CO limit or those given in Appendix SC, Special Compliance Tests.}

[Rules 62-212.400, 62-210.200 (243) (BACT), 62-4.070 (3) and 62-297.310(7)(a)4, F.A.C.]

CONTINUOUS MONITORING REQUIREMENTS

31. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO from the HRSG stacks and NO_X from all stacks in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.
    a. *CO Monitors.* The CO monitors shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.
    b. *NO_X Monitors.* Each NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.
    c. *Diluent Monitors.* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

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

- *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.
- *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]
- *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CO CEMS compliance demonstration subject to the provisions of Condition Nos. 25 and 26 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, fuel switches, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.
- *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit.

[Rules 62-4.070(3) and 62-212.400(12), F.A.C.; 40 CFR 75]

33. 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 by the time of the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate and, as applicable for fuel oil firing, the water-to-fuel ratio, that are consistent with the documented flow rate for the CT load condition. [Rules 62-4.070(3), F.A.C.]

RECORDS AND REPORTS

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

35. Monthly Operations Summary : By the 10th calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each CT for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3), 62-212.400, 62-210.200 (38) and 62-210.200 (243)(BACT), F.A.C.]

36. 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. *Natural Gas Sulfur Limit*: Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81. More recent versions of these methods or other Department approved methods may be used.

    b. *Distillate Fuel Oil Sulfur Limit*: Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods or other Department approved methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

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

37. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit. [Rule 62-297.310(8), F.A.C.].

38. Excess Emissions Reporting:

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

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

c. *NSPS Semi-Annual Excess Emissions Reports*: Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions of the applicable NSPS that occurred during the previous semi-annual period.

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

[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 and Subpart KKKK]

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

B. Auxiliary Boiler and Process Heaters (EU-014 and 015)

This section of the permit addresses the following emissions units.

ID	Emission Unit Description
014	One Large Gaseous-fueled Auxiliary Boiler (99 MMBTU/hr and 85,000 lb/hr)
015	Five Small Gaseous-fueled Process Heaters (3 MMBtu/hr)

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

   [Rule 62-212.400, F.A.C.]

2. NESHAP Subpart DDDDD Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 63, Subpart DDDDD, which applies to an industrial, commercial, or institutional boiler or process heater as defined in Sec. 63.7575 that is located at, or is part of, a major source of HAP as defined in Sec. 40 CFR 63.2.

   [40 CFR 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, or Institutional Boiler or Process Heater]

3. NSPS Subpart Dc Applicability: The 99 MMBTU/hr (85,000 lb/hr) auxiliary boiler is subject to all applicable requirements of 40 CFR 60, Subpart Dc which applies to Small Industrial, Commercial, or Institutional Boiler. Specifically, this emission unit shall comply with 40 CFR60.48c Reporting and Recordkeeping Requirements.

   [Rule 62-204.800(7)(b) and 40 CFR 60, Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, attached as Appendix Dc]

EQUIPMENT, CAPACITIES AND LIMITATIONS ON OPERATION

4. Equipment: The permittee is authorized to install, operate, and maintain one auxiliary boiler with a maximum design heat input of 99 MMBtu/hr (85,000 lb/hr) to produce steam during start up of the CTs and five 3 MMBtu/hr process heaters for the purpose of heating the natural gas supply to the CTs. [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

5. Hours of Operation: The hours of operation of the limited use gas-fueled auxiliary boiler shall not exceed 1,000 hours per year. The gas-fueled process heaters are allowed to operate continuously (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C. and 40 CFR 63.7575]

EMISSIONS, FUELS AND TESTING REQUIREMENTS

6. Auxiliary Boiler Emissions Limits:

CO (BACT, Subpart DDDDD)	VOC (BACT)
0.08 lb/MMBtu, 400 ppmvd @3% O_2	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.; 40 CFR 60, Subpart Dc; 40 CFR 63, Subpart DDDDD]

7. Auxiliary Boiler Testing Requirements: This unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. 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 combined cycle unit.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 63.7]

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

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

9. Annual CO Performance Test for Auxiliary Boilers: Pursuant to 40 CFR 63.7515(e) permittee shall conduct an annual CO test according to Sec. 63.7520. Each annual performance test must be conducted between 10 and 12 months after the previous performance test.

   [40 CFR 63.7515 and Rule 62-204.800(11)(b)84. F.A.C.]

10. Natural Gas Fired Process Heaters Emissions Limits:

CO (BACT)	VOC (BACT)
0.08 lb/MMBtu	10% Opacity, Natural Gas Specification of 2 gr S/100 SCF

   [Rule 62-212.400, F.A.C.]

11. Natural Gas Fired Process Heaters Testing Requirements: Each unit shall be stack tested to demonstrate initial compliance with the emission standards for CO and visible emissions. 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 combined cycle unit. As an alternative, a Manufacturer certification of emissions characteristics of the purchased model that are at least as stringent as the BACT values can be used to fulfill this requirement.

   [Rule 62-297.310(7)(a)1, F.A.C. and 40 CFR 60.8]

12. Natural Gas Fired Process Heaters Test Methods: Any required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}

NOTIFICATION, REPORTING AND RECORDS

13. Notification: Initial notification is required for the limited use 99 MMBtu/hr gas-fueled auxiliary boiler. Initial notification is not required for the five small gas-fueled 3 MMBtu/hr process heaters.
    [40 CFR 63.9, 40 CFR 63.7506(c) and Rule 62-204.800(11)(b) F.A.C.]

14. Reporting: The permittee shall maintain records of the amount of natural gas used in the heaters and auxiliary boilers. These records shall be submitted to the Compliance Authority on an annual basis or upon request. [Rule 62-4.070(3] F.A.C.]

C. Distillate Fuel Oil Storage Tanks (EU-016)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
016	Two Nominal 3.5 million gallon distillate fuel oil storage tanks

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for volatile organic compounds (VOC) for these emissions units.

NSPS APPLICABILITY

2. NSPS Subpart Kb Applicability: The distillate fuel oil tanks are not subject to Subpart Kb, which applies to any storage tank with a capacity greater than or equal to 10,300 gallons (40 cubic meters) that is used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Tanks with a capacity greater than or equal to 40,000 gallons (151 cubic meters) storing a liquid with a maximum true vapor pressure less than 3.5 kPa are exempt from the General Provisions (40 CFR 60, Subpart A) and from the provisions of NSPS Subpart Kb. [40 CFR 60.110b(a) and (c); Rule 62-204.800(7)(b), F.A.C.]

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain two 3.5 million gallon distillate fuel oil storage tank designed to provide low sulfur fuel oil to the gas turbines.
   [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

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

NOTIFICATION, REPORTING AND RECORDS

5. Oil Tank Records: The permittee shall keep readily accessible records showing the dimension of each storage vessel and an analysis showing the capacity of each storage tank. Records shall be retained for the life of the facility. The permittee shall also keep records sufficient to determine the annual throughput of distillate fuel oil for each storage tank for use in the Annual Operating Report.
   [Rule 62-4.070(3) F.A.C]

6. Fuel Oil Records: The permittee shall keep readily accessible records showing the maximum true vapor pressure of the stored liquid. The maximum true vapor pressure shall be less than 3.5 kPa. Compliance with this condition may be demonstrated by using the information from the respective Material Safety Data Sheets (MSDS) for the low sulfur fuel oil stored in the tanks. [Rule 62-4.070(3) and 62-212.400, F.A.C.]

D. Emergency Diesel Fire Pump (EU-017)

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
017	One nominal 300-hp emergency diesel fire pump engine and 500 gallon fuel oil storage tank.

APPLICABLE STANDARDS AND REGULATIONS

1. PSD and BACT Applicability: The Rules for the Prevention of Significant Deterioration (PSD) of Air Quality apply to this project and require BACT determinations for carbon monoxide (CO) and volatile organic compounds (VOC) for these emissions units.

2. NSPS Subpart IIII Applicability: This fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, model year selected).

   [40 CFR 60, Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines].

EQUIPMENT, CAPACITIES AND USAGE

3. Equipment: The permittee is authorized to install, operate, and maintain one diesel engine driven fire pump (approximately 300 hp) and an associated 500 gallon fuel oil storage tank.

4. Hours of Operation: The fire pump may operate in response to emergency conditions and 40 non-emergency hours per year for maintenance testing.
   [Applicant Request; Rule 62-210.200 (PTE), F.A.C.

EMISSIONS, FUELS AND TESTING REQUIREMENTS

5. Authorized Fuel: This unit shall fire low sulfur fuel oil (or superior fuel), which shall contain no more than 0.05% sulfur by weight. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

   Compliance with the distillate fuel oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to 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 methods D5453-00, D129-91, D1552-90, D2622-94, or D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of a Compliance Authority, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

6. Fire Pump Engine Emissions Limits:

   The following limits apply based on the size category of the fire pump located at the facility.

Size (hp)	CO (BACT, IIII)	NMHC*+NO_X (BACT for VOC, IIII)	PM
175 and greater	2.6 gm/bhp-hr	7.8 gm/bhp-hr	0.40

   Note 1. Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

7. Fire Pump Engine Certification: Manufacturer certification shall be provided to the Department in lieu of actual testing. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

TECHNICAL EVALUATION
AND
PRELIMINARY DETERMINATION

Florida Power Corporation dba
Progress Energy Florida
P.L. Bartow Power Plant

1,475 Megawatt Power Plant Repowering Project
New Gas-fueled Combined Cycle Unit and Simple Cycle Unit
Shutdown of three Residual Oil-fueled Units

Pinellas County

DEP File No. 1030011-010-AC (PSD-FL-381)

Florida Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
New Source Review Section

December 13, 2006

1. APPLICATION INFORMATION

Applicant Name and Address

Florida Power Corporation dba
Progress Energy Florida
100 Central Avenue, Mail Code BP39
St. Petersburg, Florida 33701

Authorized Representative:
Rufus Jackson

Processing Schedule

- July 31, 2006: Received PSD application
- August 30: Department's Request for Additional Information (RAI)
- October 3: Received Response to RAI
- October 26: Received Additional Information
- December 13: Intent to Issue, Draft PSD Permit, and Technical Evaluation Distributed

Facility Description and Location

Florida Power Corporation dba Progress Energy Florida, Inc. (PEF) proposes to construct a natural gas-fueled combined cycle unit and a simple cycle unit and to shut down the three residual oil-fueled units at the P.L. Bartow Power Plant on Weedon Island on the eastside of St. Petersburg, Pinellas County. The location with respect to other PEF facilities in Florida is shown in Figure 1. Also shown is the location of Weedon Island within Tampa Bay.

Figure 1. Bartow Power Plant in PEF System and Location of Weedon Island and Plant.

The plant is located approximately 83 km south of the PSD Class I Chassahowitzka Wilderness Area. The facility UTM coordinates are Zone 17, 342.4 km East and 3,082.6 km North.

Standard Industrial Classification Codes (SIC)

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

Regulatory Categories

Title I, Section 111, Clean Air Act, Standards of Performance for New Stationary Sources: The proposed project is subject to 40CFR60, Subpart KKKK - Standards of Performance for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers duct burners that are incorporated into combined cycle projects. Stationary combustion turbines subject to KKKK are exempt from 40 CFR 60, Subpart GG. Heat recovery steam generators and duct burners subject to KKKK are no longer subject to 40 CFR 60, Subparts Da, Db and Dc for duct burners.

Title I, Section 112, Clean Air Act, Hazardous Air Pollutants (HAP): The existing facility is a major source of HAPs. Subpart YYYY - National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines applies to any existing, new, or reconstructed stationary combustion turbine located at a major source of HAP emissions. Because the CTs for this project will have the potential for an aggregate oil-firing total of 5,000 hours (>> 1,000 hours applicability threshold) during any calendar year, Subpart YYYY is applicable.

Title I, Part C, Clean Air Act, Prevention of Significant Deterioration (PSD): The facility is located in an area that is designated as "attainment", "maintenance", or "unclassifiable" for each pollutant subject to a National Ambient Air Quality Standard. The facility is classified as a "Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input", which is one of the facility categories with the PSD applicability threshold of 100 tons per year (TPY). Potential emissions of at least one regulated pollutant exceed 100 TPY per year, therefore the facility is classified as a "Major Stationary Source" with respect to Rule 62-212.400 F.A.C.

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

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

Clean Air Interstate Rule (CAIR): The new combustion turbine-electrical generators may be subject to CAIR pending finalization of DEP rules.

Florida Power Plant Siting Act (Siting): The facility was <u>not</u> certified pursuant to Siting under 403.501-519, F.S. or Chapter 62-17, F.A.C. The proposed project is <u>not</u> subject to Siting because there will be no net increase in <u>steam</u>-generated electrical power. [Design; Letter from Applicant to Siting Office dated December 19, 2005]

2. PROPOSED PROJECT

Project Description

The project is the construction of a gas-fueled combined cycle unit with a nominal rating of 1,280 megawatts (MW) at ISO conditions and a gas-fueled simple cycle unit combustion turbine-electrical generator with a nominal rating of 195 MW at ISO conditions.

The combined cycle unit will consist of: four Siemens SGT6-5000F combustion turbine-electrical generators (CTG) with a nominal rating of 215 MW at ISO conditions when practicing power (steam) augmentation; four supplementary-fired heat recovery steam generators (HRSG's) each equipped with a nominal higher heating value (HHV) 500 million Btu per hour (mmBtu/hr) duct burner; and a single nominal 420 MW steam-electrical generator (STG).

Each CTG within the combined cycle unit will also be capable of operating in simple cycle by directing the exhaust to a bypass stack instead of to the respective HRSG. Thus the project will include eight stacks measuring approximately 120 feet in height.

The simple cycle CTG will exhaust through its own 120 foot stack. All CTGs will be equipped with evaporative coolers to condition incoming air at high ambient temperatures. Each CTG will be capable of firing backup low sulfur (<0.05% S) distillate fuel oil for 1,000 hours per year (hr/yr). Two 3.5 million gallon distillate fuel oil storage tanks are included.

A single auxiliary boiler with a nominal capacity of 85,000 pounds per hour (lb/hr) of steam and a heat input rating less than 100 mmBtu/hr will be included for the initial combined cycle unit startup and occasionally thereafter when steam is not available during a startup.

Five gas-fired fuel heaters each with nominal heat input ratings of 3 mmBtu/hr will be provided to maintain natural gas fuel for the CTGs at temperatures above the dew point. A nominal 300 hp diesel-fueled emergency fire pump is also included. Following is a listing of the new emissions units for the proposed project.

ID	Emissions Unit Description
009	Unit 4A – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
010	Unit 4B – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
011	Unit 4C – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
012	Unit 4D – one 215 MW (ISO) gas turbine with supplementary-fired heat recovery steam generator*
013	Unit 5 – one 195 MW (ISO) gas turbine operating in simple cycle mode
014	One nominal 85,000 lb/hr (99 mmBtu/hr) auxiliary boiler
015	Five nominal 3 mmBtu/hr gas-fired process heaters
016	Two nominal 3,500,000 gallon Distillate Fuel Oil Storage Tanks
017	One nominal 300 horsepower diesel-fueled emergency fire pump

* ISO indicates nominal rating at sea level, 59 degrees F and 60% relative humidity. The ratings shown for the CTGs associated with the combined cycle unit reflect gas firing and power (steam) augmentation.

Following are additional project characteristics.

- Primary Controls: CO, PM/PM_{10}, and VOC will be minimized by the efficient combustion of natural gas and distillate oil at high temperatures. Emissions of SAM and SO_2 will be minimized by firing natural gas and low sulfur distillate oil. NO_X emissions will be reduced with dry low-NO_X (DLN) combustion technology for gas firing and water injection for oil firing.
- Add-on Controls: Selective catalytic reduction (SCR) systems will be installed on the CTGs used in the combined cycle unit to further reduce NO_X emissions during combined cycle operation. The extent of reduction below the permitted emission limit will depend on the company's NO_X strategy to comply with the Clean Air Interstate Rule (CAIR).

- Continuous Monitors: Each CTG stack equipped with continuous emission monitoring systems (CEMS) as required to monitor NO_X emissions in accordance with the acid rain provisions. Each HRSG stack will have a NO_X CEMS and a CO CEMS that will be employed for demonstration of continuous compliance with certain Best Available Control Technology (BACT) determinations. Flue gas oxygen content or carbon dioxide content will be monitored as a diluent gas.

The following figure includes a photograph from the Progress Energy website of the three existing residual oil-fueled units taken in a south/southwesterly direction. The other graphic is an artist rendition of the combined cycle unit in an east/northeasterly direction. The eight stacks associated with the combined cycle are clearly shown. Also shown are the stacks of the three existing units destined for shutdown.

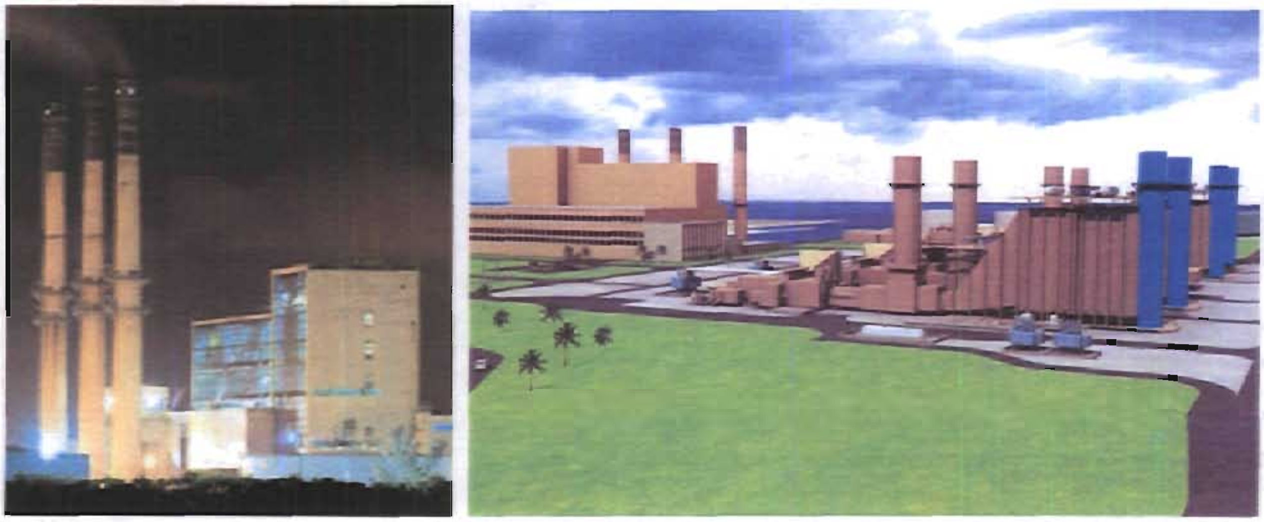

Figure 2. P.L. Bartow Units 1, 2 and 3. Artist's Rendition of New Combined Cycle Unit

The shut down of the three units will be quite noticeable as they are presently fueled by 2.5% sulfur residual fuel oil. Also the existing units are subject to a 40% visible emissions standard and are allowed even greater opacity during soot blowing. By contrast, the new unit will use inherently clean fuels and will typically exhibit no visible emissions.

The project will also require, via separate permits, the upgrading about four miles of underground transmission lines and the construction of a 17-mile long underwater natural gas pipeline by Gulf Stream Natural Gas L.L.C.

PEF requests that two of the new CTGs be available for simple cycle service for a period of seven months prior to shut down of Units 1, 2 and 3. The other two CTGs associated with the combined cycle unit will be placed in service as part of the combined cycle unit is in service after Units 1, 2 and 3 shut down. The ramifications of the early startup of two CTGs in simple cycle are discussed below.

Process Description

A gas turbine is an internal combustion engine that operates with rotary rather than reciprocating motion. A longitudinal section diagram of a Siemens SGT6-5000F (compressor, combustor section and rotor inside of casing) is shown in the left hand side of the figures below. The photograph (Siemens 2005 PowerGen presentation) on the right hand side of the figure is of the compressor and rotor section within the bottom half shell. The compressor rotating blades are on the left hand side of each graphic and the 4-stage expansion section is towards the right.

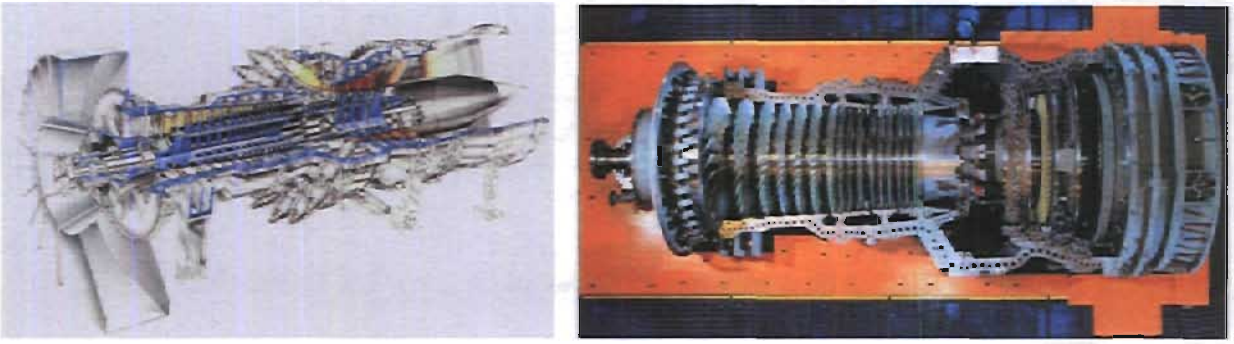

Figure 3. SGT6-5000F. Internal View and Overhead View of Compressor and Rotor.

Ambient air is drawn into the 16-stage compressor of the 5000F where it is compressed to a pressure ratio of approximately 17 atmospheres. The compressed air is then directed to the combustor section, which consists of 16 separate air-cooled, can-annular, Dry Low NO_X (DLN) combustors. Fuel is introduced, ignited, and burned. The combustor outlet temperature is on the order of 2,500 °F.

The hot combustion gases routed through the air-cooled transition pieces then are diluted with additional cool air from the compressor and directed to the turbine (expansion) section. Energy is recovered in the turbine section in the form of shaft horsepower, of which typically more than 50 percent is required to drive the internal compressor section. The balance of recovered shaft energy is available to drive the external load unit such as an electrical generator. Turbine exhaust gas (TEG) is discharged at a temperature of approximately 1100 °F and high excess oxygen. The TEG is available for additional energy recovery.

A basic combined cycle unit with only one CTG, unfired HRSG and a steam turbine-electrical generator (STG) is depicted in Figure 4. The heat from the reheated TEG is used to raise steam in the HRSG. The steam from the HRSG, in-turn, drives the STG producing additional electrical power.

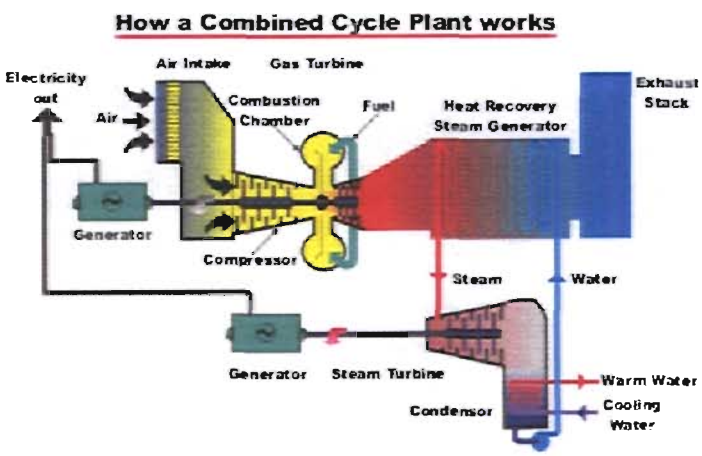

Figure 4. Combined Cycle Unit (Unfired HRSG)

The proposed project will have four CTGs and four HRSGs that will drive a single STG. The TEG will be reheated by natural gas fired in the duct burners located within each HRSG. Some of the steam will be returned to the CTGs to produce extra power by steam augmentation.

In simple cycle mode, the thermal efficiency of the Siemens SGT6-5000F is approximately 37 percent (%) on the basis of lower heating value (LHV) and 34% on the basis of higher heating value (HHV). In combined cycle mode, the thermal efficiencies are approximately 57% and 52% based on LHV and HHV respectively.

Additional features of the combined cycle unit include:

- Inlet Conditioning: Evaporative cooling is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. This is typically implemented at ambient temperatures of 60° F or higher.
- Duct Burning: Gas-fired duct burners (DB) can be used in the HRSG to provide additional heat to the turbine exhaust gas and produce even more steam-generated electricity. Duct firing is useful during periods of high-energy demand. The applicant requests 2,434 hours of duct burning per year for each HRSG.
- Power (Steam) Augmentation (PA): Steam for PA is taken from the HRSG and is introduced into the gas turbine compressor discharge, thus increasing the power produced by the expander portion of the turbine. PA causes greater uncontrolled CO emissions. The applicant requests 1,688 hours of PA for each CTG.
- Simple Cycle (SC) Mode: Bypass stacks have been included in the design allowing the CTGs associated with the combined cycle unit to operate in SC mode. This is a low probability scenario given the lower thermal efficiency. However it allows operation if there are STG, HRSG, or main condenser problems that would preclude operation in combined cycle mode.

Further process details are provided in the Draft BACT determination, Section 4.0 below.

3. RULE APPLICABILITY

Federal Regulations

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

Title 40	**Description**
Part 60	New Source Performance Standards (NSPS)
Part 63	National Emission Standards for Hazardous Air Pollutants (NESHAP)
Part 72	Acid Rain - Permits Regulation
Part 73	Acid Rain – Sulfur Dioxide Allowance System
Part 75	Acid Rain - Continuous Emissions Monitoring
Part 76	Acid Rain - Nitrogen Oxides Emissions Reduction Program
Part 77	Acid Rain - Excess Emissions
Part 96	NO_X Budget Trading Program for State Implementation Plans

State Regulations

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

Chapter	Description
62-4	Permitting Requirements
62-204	State Implementation Plan (AAQS, PSD Increments, adoption of Federal Regulations)
62-210	Stationary Sources of Air Pollution – General Requirements
62-212	Preconstruction Review (including PSD Requirements)
62-213	Operation Permits for Major Sources of Air Pollution
62-214	Acid Rain Program Requirements
62-296	Emission Limiting Standards
62-297	Emissions Monitoring

Description of PSD Applicability Requirements

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

The PEF P.L. Bartow Power Plant is a Major Stationary Source with respect to the PSD Rules because it is a fossil fuel-fired steam electric plant of more than 250 million Btu heat input and has the potential to emit 100 tons per year or more of a PSD pollutant.
(Rule 62-210.200(185)(a)1., F.A.C.)

The Repowering Project is a Major Modification of a Major Stationary Source if there will be a net emissions increase greater than the significant emission rate (SER) of a PSD pollutant. The SER means a rate of pollutant emissions that would equal or exceed: 100 tons per year (TPY) of carbon monoxide; 40 TPY of nitrogen oxides (NO_X), sulfur dioxide (SO_2), or volatile organic compounds (VOC); 25 TPY of particulate matter (PM); 15 TPY of PM smaller than 10 microns (PM_{10}); 7 TPY of sulfuric acid mist (SAM); or 0.6 TPY of lead (Pb). [Rule 62-210.200(185)(a)1., F.A.C.]

For each pollutant with a net emission increase exceeding the respective SER, the applicant must propose the Best Available Control Technology (BACT) as defined in Paragraph 62-210.200(39), F.A.C. to minimize emissions and conduct an ambient impact analysis as applicable. BACT determinations for this project are required for CO and VOC only for reasons described below.

The other part of PSD review requires an Air Quality Analysis consisting of: an air dispersion modeling analysis to estimate the resulting ambient air pollutant concentrations; a comparison of modeled concentrations from the project with National Ambient Air Quality Standards and PSD Increments; an analysis of the air quality impacts from the proposed project upon soils, vegetation, wildlife, and visibility (Air Quality Related Values – AQRVs); and an evaluation of the air quality impacts resulting from associated commercial, residential, and industrial growth related to the proposed project. [Rule 62-212.400(5) through (9), F.A.C.]

Estimates of Net Emissions Increases

The new combined cycle unit and new simple cycle unit will result in emissions of CO, NO_X, SO_2, PM/PM_{10}, SAM and VOC. The shut down of the three residual oil-fueled units will result in reductions of the same pollutants.

The following table is a summary of the emissions increases and decreases resulting from the proposed project to determine which pollutants will be emitted in excess of their respective SERs.

Table 1. Applicant's Summary of Net Emissions Increases and PSD Applicability for the P.L. Bartow Plant Repowering Project Permanent Scenario.

Pollutant	Baseline Emissions TPY	New Units Potential Emissions TPY	Net Emissions Increases (Decreases) TPY	PSD SER TPY	PSD?
SO_2	24,816	466	(24,350)	40	No
PM/PM_{10}	804/559	413/413	(391)/(146)	25/15	No
NO_X	4,043	3,191	(852)	40	No
CO	367	938	571	100	Yes
VOC	57	145	88	40	Yes
SAM	423	72	(351)	7	No
Lead	0.10	0.06	(0.04)	0.6	No
HAPs	No Estimate	23.1	< 23.1	NA	No

The baseline emissions are for Units 1, 2 and 3 that are destined for shut down. SO_2 and NO_X emissions were calculated using the continuous emissions monitoring systems (CEMS) required by the Acid Rain Program. These two pollutants account for 95% of the present PSD pollutant emissions. The rest of the emissions were calculated by annual emissions tests or by emission factors.

There will be decreases in all PSD pollutants except for CO and VOC. Given the high opacity limits at the existing units, the quality of fuel used and the frequency of soot blowing, the Department believes that baseline annual PM/PM_{10} emissions are greater than estimated and that reductions will be greater than estimated. The applicant's estimates of baseline PM/PM_{10} and CO are likely conservative and tend to make it more likely that PSD will apply than otherwise.

Although no baseline estimates of HAPs are provided, the switch from residual fuel oil to inherently clean fuels will reduce emissions of nickel (Ni, a HAP) and vanadium (V, not classified as a HAP) that tend to catalyze the oxidation of SO_2 to SAM.

According to the applicant's estimates, net emissions increases of CO and VOC will be greater than their respective SERs. Therefore, a PSD review and determinations of BACT are required for those pollutants.

The applicant has requested authorization to use two of the CTGs for a seven month period prior to the permanent shut down of Units 1, 2 and 3. During the period December 2008 through June 2009, those CTGs will be operated as simple cycle peaking units (intermittent duty with rapid startup to full load operation) prior to their incorporation into the combined cycle unit.

Because this initial phase will occur prior to the shut down of Units 1, 2 and 3 it is not possible to take "credit" for contemporaneous emissions reductions when calculating net emissions increases. Rather than making permanent and enforceable emissions reductions from Units 1, 2 and 3 the applicant will insure that emissions from the initial simple cycle phase will not exceed the respective significant emission rate (SER) for any PSD pollutant.

The following table is a summary of the emissions increases resulting from the operation of two CTGs in simple cycle mode.

Table 2. Applicant's Summary of Net Emissions Increases and PSD Applicability for the Operation of two CTGs in Simple Cycle Mode for Seven Months.

Pollutant	Emissions from Two Simple Cycle CTGs tons	PSD SER TPY	PSD?
SO_2	<< 39	40	No
PM/PM_{10}	< 24/14	25/15	No
NO_X	39	40	No
CO	< 99	100	No
VOC	<< 39	40	No
SAM	<< 6	7	No
Lead	<< 0.6	0.6	No

According to the equipment characteristics NO_X is the controlling pollutant with respect to PSD applicability. Over three times as much NO_X will be emitted compared with CO. During this temporary period of simple cycle peaking, the Department will limit NO_X emissions to 39 tons from both units (combined) with compliance demonstrated by CEMS. In addition, the total aggregate hours of operation will be limited to 1,100 hours during this period. By doing so, the Department will have reasonable assurance that emissions of all pollutants will be less than their respective SERs. The units will still be subject to the unit specific requirements of this permit and 40 CFR 60, Subpart KKKK-Standards of Performance for Stationary Combustion Turbines.

4. DRAFT DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 BACT Determination Procedure

BACT is defined in Paragraph 62-210.200 (39), FAC as follows:

(a) An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account:

1. *Energy, environmental and economic impacts, and other costs;*
2. *All scientific, engineering, and technical material and other information available to the Department; and*
3. *The emission limiting standards or BACT determinations of Florida and any other state; determines is achievable through application of production processes and*

available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.

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

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

(d) In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63.

According to Rule 62-212.400(4)(c), F.A.C., the applicant must at a minimum provide certain information in the application including:

(c) A detailed description as to what system of continuous emission reduction is planned for the source or modification, emission estimates, and any other information necessary to determine best available control technology (BACT) including a proposed BACT;

According to Rule 62-212.400(10), F.A.C., the Department is required to conduct a control technology review and shall not issue any permit unless it determines that:

(a) The owner or operator of a major stationary source or major modification shall meet each applicable emissions limitation under the State Implementation Plan and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.

(b) The owner or operator of a new major stationary source shall apply best available control technology for each PSD pollutant that the source would have the potential to emit in significant amounts.

(c) The owner or operator of a major modification shall apply best available control technology for each PSD pollutant which would result in a significant net emissions increase at the source. (This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.)

(d) The owner or operator of a phased construction project shall adhere to the procedures provided in 40 CFR 52.21(j)(4), adopted and by reference in Rule 62-204.800, F.A.C.

4.2 NO_X Emission Technology and Limits (non-BACT)

Although a BACT determination is not required for NO_X, it is nevertheless useful to discuss the technology to be employed for NO_X in order to gain a better understanding of the possibilities and limitations to CO and VOC control. Additionally, it is necessary to insure that the project will comply with the NO_X requirements given in 40 CFR 60, Subpart KKKK.

NO$_X$ Formation

NO$_X$ forms in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. It also forms by oxidation of nitrogen present in the fuel.

Thermal NO$_X$. Thermal NO$_X$ forms in the high temperature area of the gas turbine combustor as seen on the left hand side of Figure 5. Thermal NO$_X$ increases exponentially with increases in flame temperature and linearly with increases in residence time. By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO$_X$ formation. The relationship between flame and firing temperature, output and NO$_X$ formation are depicted in the right side of Figure 5, which is from a GE discussion on these principles.

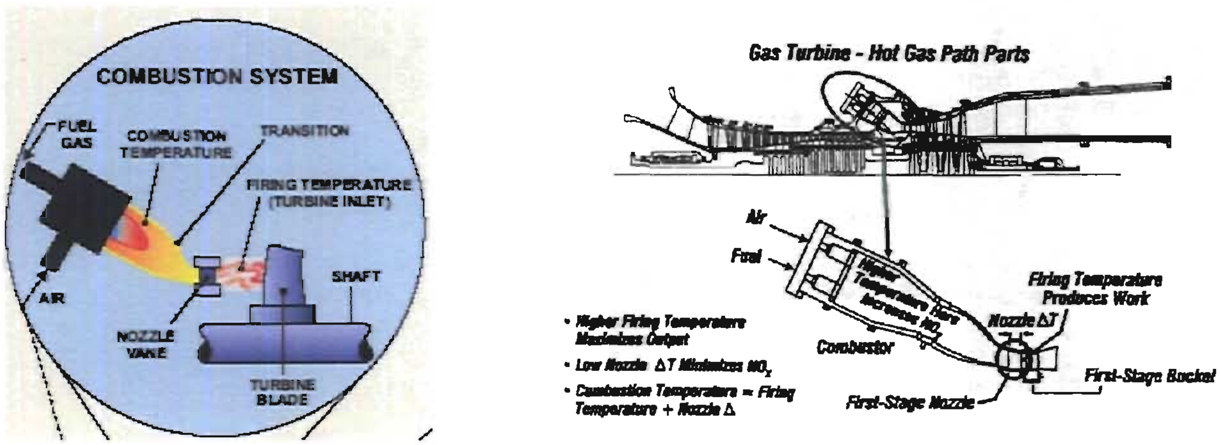

Figure 5. Relation between Combustion and Firing Temperatures and NO$_X$ Formation

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO$_X$ formation. Cooling is also required to protect the first stage nozzle.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for each turbine of the PEF project.

Descriptions of Available NO$_X$ Controls

Wet Injection. Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO$_X$ formation. There is a physical limit to the amount of water or steam that may be injected before flame instability or cold spots in the combustion zone would cause adverse operating conditions for the combustion turbine.

Advanced dual fuel combustor designs can tolerate large amounts of steam or water without causing flame instability and can typically achieve NO$_X$ emissions in the range of 30 to 42 ppmvd when employing wet injection for backup fuel oil firing. Wet injection results in control efficiencies on the order of 80 to 85% for oil firing. These values often form the basis for further reduction to BACT limits by other techniques as discussed below.

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

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

The traditional DLN combustor for the Siemens/Westinghouse 501FC engine (the predecessor of the SGT6-5000F) was a partially premixed combustor, with a center-core pilot diffusion flame surrounded by eight lean premix nozzles where the fuel is injected at multiple ports inside the combustor and mixes with the combustion air in advance of the flame zone.

Figure 6 shows the combustor with the air bypass configuration (eliminated from some recent models).[1]

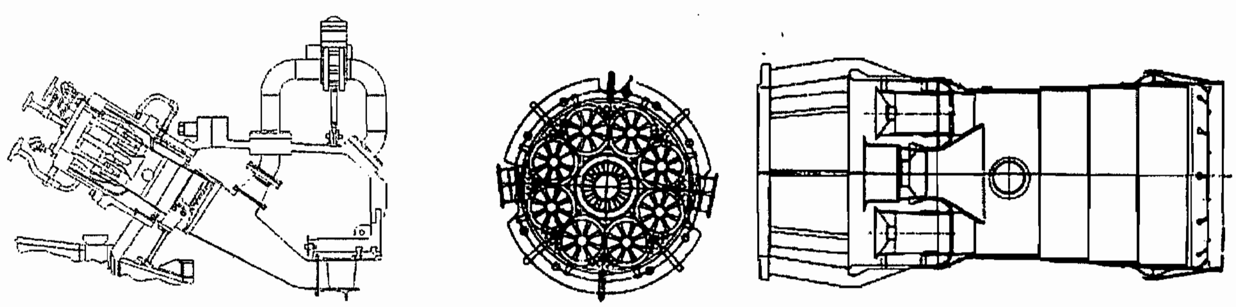

Figure 6. Siemens/Westinghouse 501FC DLN System and Combustion Basket.

In the combustor, natural gas is injected into three or four stages; pilot, A, B, and C (for certain configurations). The diffusion flame pilot injector provides stability for the premixed A, B, and C-stages. Because a diffusion flame has high NO_X emissions it is necessary to minimize the amount of flow through the pilot.

The majority of the fuel is injected upstream of the pilot through the main A and B stages. The main fuel is injected tangential to the flow direction through 8 fuel rockets each with 4 fuel injection holes. This fuel premixes with the air before reaching the combustion zone. During the C-stage, a small amount of fuel is injected in a zone called the "top hat" region before the flow enters the basket.

The C-stage provides additional premixing of the fuel and air and allows a reduction in the pilot fuel flow. Typically the DLN combustor is ignited on the pilot and A-stage. The B-stage is initiated at 30% load and the C-stage is initiated at 50% load.

According to Siemens, a DLN combustion system improvement reduced NO_X from >25 parts per million by volume (ppmv) down to <9 ppmv and was successfully demonstrated on a service unit in 2004.[2] The exact profile with respect to load for that installation is not known. Presumably values significantly greater than 9 ppmvd occur during the pilot, A-Stage, B-Stage and early C-Stage operational loads.

The exact features of the DLN (or possibly Ultralow NO_X - ULN) technology that will be incorporated into the proposed project are not yet known to the Department. However, the applicant has proposed to meet NO_X limits of 15 ppmvd for natural gas firing to meet the requirements of 40 CFR 60, Subpart KKKK for combined cycle units. It appears that this value can be accomplished with the described DLN technology.

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

The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

Figure 7 below is a diagram of the typical Nooter Eriksen (NE). NE supplied the HRSGs for the PEF Hines Energy Complex Power Block 1 also shown in the figure.

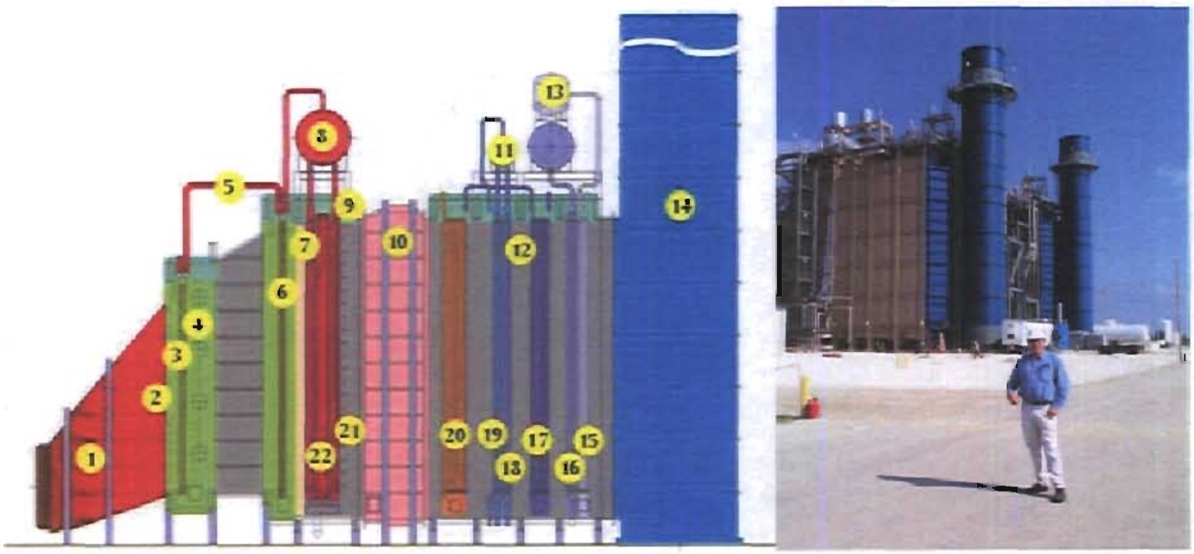

Figure 7. Key Nooter Eriksen HRSG Components (10 is SCR) and PEF Hines Block 1

Components 10 and 21 represent the SCR reactor and the ammonia injection grid. In this arrangement the SCR system lies between the high pressure evaporator (22) and the high-pressure economizer (20) where the temperature requirements for conventional SCR can be met.

The external lines to the ammonia injection grid are easily visible in the photograph. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles. The SCR catalyst is typically augmented or replaced over a period of several years although vendors typically guarantee catalysts for about three years. Excessive ammonia use can increase emissions of CO, ammonia (slip) and particulate matter (when sulfur-bearing fuels are used).

In the given design, the duct burner (4) lies between a "split" high pressure superheater (3 and 6). For future reference in discussion below, the CO catalyst in this design is Component 7.

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

Although the combined cycle unit can likely comply with the requirements of Subpart KKKK, PEF will install an SCR system within each of the four HRSGs. When used, this will further insure compliance and will also provide flexibility in achieving PEF's overall company strategy pursuant to the Clean Air Interstate Rule (CAIR).

4.3 CO and VOC BACT Determination

CO and VOC Formation and Combustor Characteristics

CO and VOC are emitted from combustion turbines due to incomplete fuel combustion. Most combustion turbines incorporate good combustion to minimize emissions of CO and VOC. The obvious control techniques are based upon high temperature, sufficient time, turbulence, and excess air. Additional control can be obtained by installation of oxidation catalyst.

The following table contains proposed CO and VOC emission estimates provided in the application for the SGT6-5000F CTGs that will be used for the project.

Table 3. Applicant's CO and VOC Estimates for SGT6-5000F CGTs (ppmvd @15% O_2)

Load Range	Fuel/Mode	CO	VOC
70-100%	Gas	4	1
60-70%	Gas	10	4
100%	Gas/Duct Burner	9	2
70-100%CO	Fuel Oil	30	10

The projections while firing natural gas in the range of 70-100% of full load are consistent with the full load experience of the predecessor Siemens-Westinghouse 501F (SW 501F) CGTs installed at the PEF Hines Energy Complex. Hines CGTs 1A and 1B exhibited full load CO and VOC emissions during all compliance runs of less than 1.0 and less than 0.6 ppmvd for the two pollutants respectively.[3] CO and VOC emissions should be very low based on the high combustion temperature and the relatively high temperature and excess air in the turbine exhaust gas (TEG).

However, there is concern regarding the performance on natural gas at loads less than 70%. Based on the values in the above table, performance is projected to degrade somewhat by 60 to 70% load. Additionally, it is known that the applicant wants the ability to turn down the load to levels less than shown in the table. Therefore, it is important to have an understanding of performance at low load because of CTG startups and shut downs that may or may not involve HRSG or STG startups and shut downs. Fuel oil and duct burner performance are discussed further below.

The Department requested manufacturer's curves showing expected emissions with respect to CGT load as percent of full load.[4] In its response, the applicant advised that according to Siemens "they do not provide 'curves' for various loads".[5] In response to a request related to a separate project, PEF provided tabulated CO data covering startups, shut downs, fuel switches, tunings and malfunctions.[6] The data comprise experience from four SW501F CGTs that are (at least to the untrained eye) identical to the SGT6-5000F.

The Department entered the data into a spreadsheet and produced the following charts relating CO emissions to the described events.

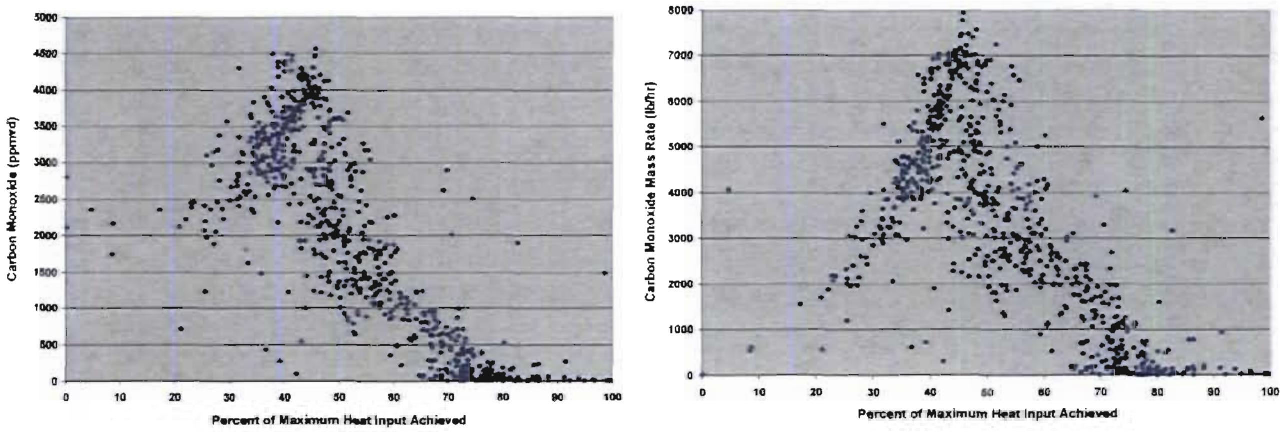

Figure 8. CO Emissions during Certain Low Load and Transient Conditions

The data indicate that CO emissions are very high at least during the transient periods related to the mentioned events. During a number of hours more than 2 tons of CO were emitted at concentrations of 8,000 ppmvd at roughly 50% of full load when the C-Stage is initiated.

The Department also focused on operation greater than 50% of full load to assess the likely performance of the units given that the data are indeed representative of such operation unassociated with transients. The results are shown in the graph on the following page. Again the data suggest the possibility of high CO emissions.

Siemens is at least aware of these issues. The Department obtained a recent paper presented by Siemens at the 2005 PowerGen Conference. In it Siemens described some possible improvements allowing faster startup times and also the manner by which they can achieve low CO emissions at partial loads on the SGT6-5000F CTG.[7] According to Siemens (with some minor paraphrasing):

"The original startup time from initiation to full power took approximately 30 minutes. The improved start time capability is as follows: 5 minutes from start initiation to minimum load, and then the GT is loaded at 30 MW/minute. This permits 150 MW within 10 minutes.

To achieve the improved start capability the following steps were taken:

1. *Implement static frequency converter (static start), whereby the CTG generator operates as a motor replaces the mechanical starter motor. This allows more efficient and faster rotor acceleration than the equivalently sized mechanical starting motor.*

2. *The turning gear (TG) speed was increased from 3 rpm to 120 rpm. The higher TG speed enables the generator rotor wedges to lock up and also helps the engine cool down faster, because the turbine parts are cooled faster and tip clearances are similar to the cold tip clearance."*

"Reduced low load CO emissions were achieved by operational modifications which include a second modulating circuit added to turbine cooling air supply. When load is reduced, the second modulating circuit is opened bypassing additional cooling air around the combustor. Bypassing air around the combustor increases combustor flame temperature and hence limits CO production. There are other measures which can be taken to reduce CO if necessary, including changes to valve scheduling to allow compressor air to be bypassed into the exhaust. With this equipment & operational changes, CO is kept to <10 ppm down to between 45% and 50% load. This CO reduction will reduce total CO mass emissions by 70% per startup-shutdown cycle."

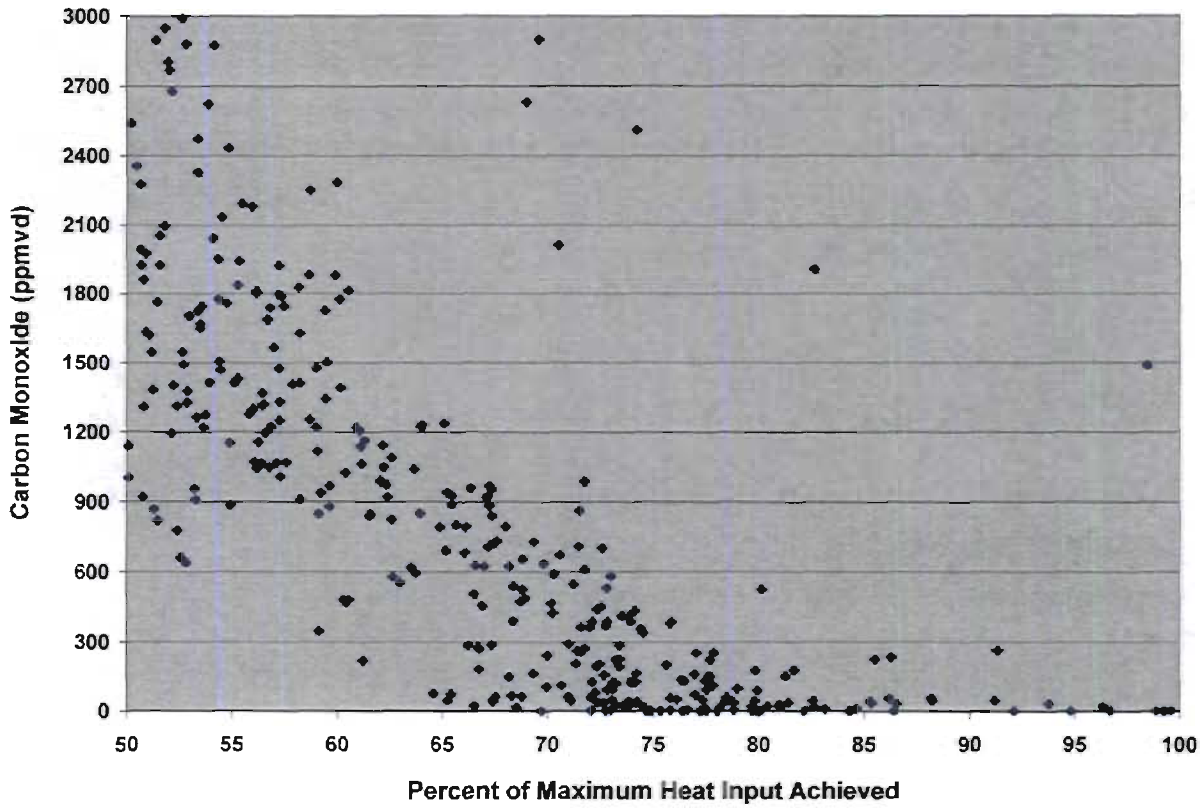

Figure 9. CO Emissions during Certain Medium Load Conditions

The following figures from the Siemens presentation compare original to improved startup characteristics. The graph on the left demonstrates the reduction of startup times which may be minimized to reduce CO emissions during these periods. The graph on the right suggests that the operating cycle can be improved to extend the "low CO" range to loads less than 50%.

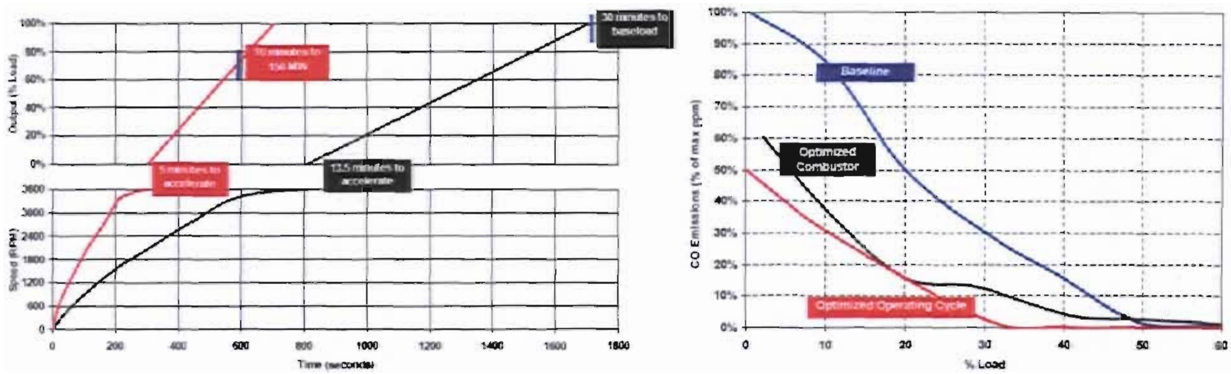

Figure 10. Improved Startup Times to High Load. Relative CO Emissions at Low Load.

The Department does not dispute that the emissions can be reduced to less than 10 ppmvd in the 45-50% load range as suggested by the Siemens paper. However, the applicant has not provided information regarding the measures to actually be incorporated to avoid very high CO emissions during startups, shutdowns and low load (whether or not the low load is associated with startups and shutdowns).

The options described by Siemens may be available for the project to help achieve BACT level CO and VOC emission limits and possibly avoid installation of oxidation catalyst.

<u>Low Load Considerations</u>

As previously discussed and shown in Figures 8 and 9, emissions from existing SW501F CGTs at PEF Hines Energy Complex during low load operation are extremely high when compared to operation above 70 % load. The data shown in the graphs include startups, shutdowns, fuel switches, tunings and malfunctions. Emissions during periods of startups, shutdowns, and fuel switches, as well as during "idling" at less than full load, as they relate to this project are discussed below.

Startup and Shutdown

Simple Cycle Operation:

Frequent startups and shutdowns are expected of the Unit 5 simple cycle gas turbine, as well as the two CTs designated to operate in simple cycle mode during the slated "interim" period. Note that the emission levels in the graph in Figure 8 represent hourly averages. The Siemens SGT6-5000F in SC mode can be at baseload (Figure 11) and achieve low emissions within 30 minutes of initiation of startup.

It can also be seen from Figure 8 that emissions ramp up and peak at about 40 to 50 % load. Therefore, total emissions for a "startup" cycle would include a period at the beginning of startup with very low emissions, a period during the middle of startup with very high emissions, and the remainder of startup and the rest of the hour with normal levels of mass emissions. The actual hourly emission rate would therefore likely be lower than that implied by the graphs. Additionally, with the Siemens operational enhancements for improved startup capability and part load CO emissions reduction described earlier, startup emissions should be significantly reduced.

The CTGs of the combined cycle unit will be equipped with bypass stacks to allow for SC operation during periods such as steam turbine or main condenser failures. This mode will be used only to ensure reliability of the units and would naturally be minimized by the facility because of the lower efficiency realized in SC operation. Additionally, SC operation of the CTGs for this unit would require cooling of the ducting between the CTG and the HRSG in order to remove one plate and to install another to divert turbine exhaust gas (TEG) to the bypass stack. Operation under this scenario is expected to be very limited therefore the number of startups using the bypass stacks will be very low.

Combined Cycle Operation

For a CC cold unit startup, the gas turbine will operate at a very low load (less than 10 percent) while the heat recovery steam generator and the steam turbine-electrical generator are heated. This can take several hours of low load operation. Following the slated "interim" period, Bartow Units 1 through 4 will primarily operate in continuous combined cycle mode. Although emissions from a CC startup will be significantly higher than that from a SC startup, it is expected that very few will actually occur. Typically cold startup of the steam turbine electrical generator (STG) occurs less than twice per year.

The above discussion focuses on unit startups. However, the same ideas can be applied to shutdowns which are generally of much shorter duration and account for significantly fewer overall emissions.

Operation Below Full Load Other Than Startup and Shutdown

During off-peak hours when demand for electricity is lowest, many CC units are often turned down to loads less than 100 % in order to conserve fuel and lower costs. Units 1 through 4 will be base loaded units and are normally expected to operate at, or near, 100 % load. However, these units will not be limited to full load operation, and even when operating at the lower loads they will be required to meet the CO emissions limits and demonstrate compliance by CEMS. According to Siemens, with the recent enhancements (if implemented), CO emissions of less than 10 ppm can be maintained at operation to between 45 and 50 % load.

Fuel Switching

The principal reason for increased emissions during fuel switching is generally the same as that for startup – low load operation. It is necessary to bring the CT to low load operation for a limited amount of time in order to switch from one fuel to the other. Each turbine will be limited to 1,000 hours of oil use as a back-up fuel. Fuel switching is expected to be infrequent, but will vary depending on fuel availability and cost.

Fuel Oil Considerations

Fuel oil firing is expected to be minimal but is actually requested for 1,000 hours per year per turbine. The annual potential to emit (PTE) CO emissions at 1,000 hours of operation at the requested BACT values is comparable to the annual PTE for the full time natural gas case, excluding power augmentation and duct burner operation.

The CO and VOC estimates given in Table 3 while firing fuel oil near full load are excessive and in contrast to the compliance tests conducted at the PEF Hines Energy Complex. Whereas limits of 30 ppmvd CO and 10 ppmvd VOC are requested for fuel oil firing for the Bartow units, the full load tests at Hines indicated emissions during all compliance runs less than 1.3 ppmvd and less than 0.4 ppmvd for the two pollutants respectively.[8] However, it is possible that CO emissions when firing fuel oil exhibit the same startup, shutdown and low load characteristics as discussed above.

Again, CO and VOC emissions while firing fuel oil near full load should be very low based on the high combustion temperature and the relatively high temperature and excess air in the TEG. It would appear that some of the possible design and operational remedies described by Siemens for the low load conditions while firing natural gas can also be employed for fuel oil firing.

Duct Burner Considerations

Turbine exhaust gas (TEG) enters the HRSG at a relatively high temperature (~1,100 °F) and high excess air (> 12% O_2). In the design shown in Figure 7, some of the heat is used by the first part of the split high pressure superheater (Component 3). The gas-fired duct burner (Component 4) restores heat to the TEG prior to entering the second section (Component 6) of the split superheater.

The figure below shows an individual burner and an array comprising a duct burner. The hot TEG contains sufficient combustion air to burn the natural gas introduced into the burner array.

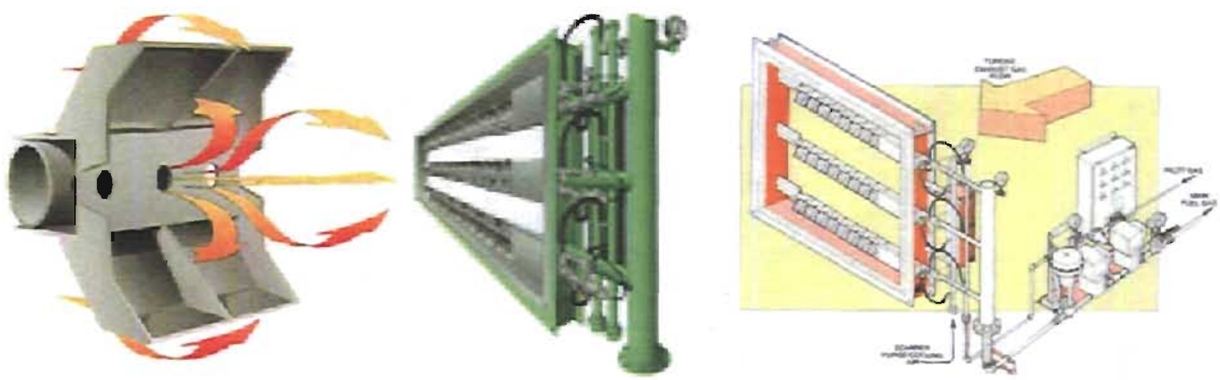

Figure 11 – Individual Burner and Array within Supplementary-Fired HRSG (Coen)

The ignition temperatures for CO and methane (not counted as VOC) are between 1,100 and 1,200 °F. VOC such as ethane and propane ignite at temperatures less than 900 °F. All of the necessary conditions (oxygen, temperature, turbulence and time) are present to minimize CO and VOC concentration increases.

Following is a table with the results of CO and VOC testing completed at the Gulf Power Lansing Smith Plant[9] and OUC Stanton Unit A. The units are GE7FA combustion turbines (CT) that are the same-class competitor to the SGT6-5000F. Tests were conducted on each combustion turbine while using duct burners (DB). CO emissions increase slightly when firing duct burners, but still remain very low. No appreciable differences in CO emissions are noted for large combustion turbines when operating on fuel oil versus natural gas.

Table 4. CO and VOC Emissions while Duct Firing – GE 7FA Units (ppmvd@15% O_2)

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

Based on the full load CGT testing at PEF Hines Energy Complex and the fact that duct burners will be used at or near full load CGT operation, the Department would expect very low CO and VOC emissions at PEF Bartow when the duct burners are used.

Comparison of PEF's Initial CO and VOC BACT Proposal with Recent Projects

Following are some of the most recent BACT determinations by the Department for CO and VOC emissions from large CTGs. PEF's proposal is included in the table for comparison.

Table 5. Recent CO and VOC Standards for "F and G-Class" CTGs

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
PEF Bartow Application	4.0 – NG (baseload - 70%, CEMS) 10.0 – NG (70-60% load, CEMS) 9.0 – NG (DB on, CEMS) 30 – FO (baseload to 70%, CEMS)	1.0 – NG (baseload – 70%, Annual Test) 4 – NG (70-60% load, Annual Test) 2 – NG (DB on, Annual Test) 10 – FO (Annual Test)
FP&L Turkey Pt.	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 14 – 24-hr NG (DB+PA) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.3 – NG (DB off, Annual Test) 1.9 – NG (DB on, Annual Test) 2.8 – FO (Annual Test)
FP&L W. County	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	1.2 – NG (DB off, Annual Test) 1.5 – NG (DB on, Annual Test) 6 – FO (Annual Test)

Table 5 (Cont). Recent CO and VOC Standards for "F and G-Class" CTGs.

Project Location	CO – ppmvd @15% O_2	VOC – ppmvd (@15% O_2)
FMPA Treasure Coast	4.1 – NG (DB off, Annual Test) 7.6 – NG (DB on, Annual Test) 8.0 – FO (Annual Test) 8.0 – 24-hr (All Modes) 6.0 - 12-month (all modes)	Not PSD
PEF Hines 4	8.0 – NG (24-hr block) 12.0 – FO (24-hr block)	1.3 – NG (Annual Test) 3.0 – FO (Annual Test)

Notes: NG = CT on Natural Gas DB = Duct Burner FO = Fuel Oil

<u>Department's CO and VOC BACT Determination</u>

Based on data and information available to the Department as presented in the above discussion, the following conclusions can be drawn:

- PEF's proposed CO emission limit for normal operation (gas firing, 70-100 % load, DB off) of 4.0 ppmvd @ 15% O_2 is acceptable and consistent with similar unit experience at the PEF Hines Energy Complex. However, the proposed limits for less than 70 % load, duct burner operation, and fuel oil firing as listed in Table 3 are excessive and in contrast to compliance test results on similar units.
- There will be considerable use of duct burners (DB). The Department believes CO emissions under DB in terms of ppmvd @15% O_2 will be approximately equal to emissions under the normal mode. PEF still estimates greater CO concentrations while using the duct burners than when operating the combustion turbine at full load. The requested value of 9.0 ppmvd @15% O_2 for this mode of operation is slightly higher than other recent BACT determinations of 7.6.
- The CO proposal of 30 ppmvd @15% O_2 while firing fuel oil appears very high when compared to past experience on existing units and other recent proposals for new units. The expectation is that CO emissions during periods of fuel oil firing will be similar to emissions during gas firing.
- PEF's proposed VOC emissions limits are similarly high for periods of duct burner operation and fuel oil firing. The same discussions presented above apply, and actual emissions of VOCs are expected to be considerably lower than proposed during these modes of operation.

The applicant has determined that CO oxidation catalyst is not cost effective for this project. According to PEF, estimated capital cost per CT is $1,422,634 and total annualized cost per CT is $688,966 resulting in a cost effectiveness of $3,956 per ton of CO removed assuming an 80% reduction in CO emissions. The Department however, does not agree with all aspects of the applicant's determination and feels that CO catalyst would be cost effective if necessary to comply with all BACT limits.

For example, capital and replacement costs are slightly lower in an independent budgetary proposal obtained by the Department for a CO catalyst system on a GE 7FA unit, than those proposed by PEF. The Department's Engelhard catalyst performance guarantee includes a maximum pressure drop across the catalyst of 0.9 to 1.0 inches water gauge (WG). The applicant's proposed cost effectiveness analysis was based on a maximum pressure drop of 1.5 to 2.0 WG. Additionally, based on experience with existing units a minimum 5-year expected catalyst life is a better representation of real-life expectations than the 3-years assumed by PEF.

PEF updated the heat rate penalty to reflect a more recent natural gas cost as requested by the Department. A cost of $9.6/MMBtu was used for the new estimate. Although this may have been the instantaneous price at the time the estimate was updated, considering the recent overall trend in natural gas prices the amount chosen may be unnecessarily high. For the last week of November prices were in the $8.00/MMBtu range.

For a more long-term look, the recently published 2007 Annual Energy Outlook presents a midterm forecast and analysis of US energy supply, demand, and prices through 2030[10]. The projections are based on results from the *Energy Information Administration's* National Energy Modeling System. The following table is an excerpt from the DOE report showing natural gas price projections in the $5 and $6 per MMBtu range through 2025. Expansion of existing and construction of new liquefied natural gas (LNG) terminals is the main reason for the long term stability in the future.

Table 6. Energy Prices by Sector and Source (2005 Dollars per Million Btu)

Sector and Source	**Reference Case**					
	2004	**2005**	**2010**	**2015**	**2020**	**2025**
Electric Power						
Distillate Fuel Oil	9.52	11.38	11.71	9.26	9.84	10.25
Residual Fuel Oil	4.99	6.96	6.58	5.60	6.08	6.58
Natural Gas	**6.11**	**8.18**	**6.22**	**5.50**	**5.76**	**6.05**
Steam Coal	1.40	1.53	1.71	1.60	1.58	1.63

CO and VOC limits consistent with recent BACT determinations issued by the Department will be set for PEF Units 4 and 5. These limits should be readily met without the use of oxidation catalyst systems assuming fast startups and high load operation. Each HRSG stack will be equipped with a CO CEMS, and a reasonable continuous 24-hour emissions limit will be set to cover all modes of operation. This is consistent with recent determinations for FPL Turkey Point and FMPA Treasure Coast combined cycle projects. If additional measures are needed in the future to meet the CO emission limits due to extended low load operation by the CC unit 4 CTs, then oxidation catalyst will be a cost effective alternative control strategy.

Because full load is quickly reached, and operation will be limited to loads greater than 70 % during simple cycle operation, oxidation catalyst is not a consideration for the Unit 5 CT nor will it be required prior to the bypass stacks on Unit 4. Simple cycle operation of the Unit 4 CTs is expected to be minimal. Compliance determinations with the CO standards during simple cycle operation will be based on required stack tests.

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

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

Table 7. Draft BACT Determination

Pollutant	Fuel	Method of Operation[a]	Stack Test, 3-Run Average		CEMS[c] Block Average
			ppmvd @ 15% O_2	lb/hr[b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr[d] 6, 12-month[f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC[e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC[e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

5. NEW SOURCE PERFORMANCE STANDARDS APPLICABLE TO GAS TURBINES AND DUCT BURNERS

Stationary gas turbines are subject to the federal New Source Performance Standards in Subpart KKKK of 40 CFR 60. These requirements result in the following standards for the proposed CTs. Subpart KKKK also applies to emissions from any associated HRSG and duct burners.

- NO_X (gas) ≤ 15 ppm @ 15% O_2 or 0. 43 lb/MWh (4-hr average);
- NO_X (oil) ≤ 42 ppm @ 15% O_2 or 1.3 lb/MWh (30 operating day average); and
- SO_2 ≤ 0.90 lb/MWh or ≤ 0.060 lb SO_2/MMBtu*

*Purchase contracts or tariff sheets can be used in place of fuel sulfur content monitoring by demonstrating sulfur content of no more than 0.05% (500 ppmw) by weight fuel oil or 20grains of sulfur per 100 standard cubic feet of natural gas.

6. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS APPLICABLE TO GAS TURBINES

The Bartow Power Plant is an existing source of hazardous air pollutant emissions. As such, the proposed new combustion turbines will be subject to NESHAP Subpart YYYY- National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines, which became final on March 5, 2004.[11]

On April 7, 2004, EPA published two proposals that potentially affect applicability of Subpart YYYY.[12] EPA has stayed the applicability of YYYY to certain <u>gas-fired</u> units and proposed to permanently delete such units (as well as other classes) from the list of sources subject to the regulation.

For a stationary combustion turbine to qualify as a gas-fired unit under Subpart YYYY each stationary combustion turbine which is equipped both to fire gas and oil, must be located at a major source where all new, reconstructed, and existing stationary combustion turbines fire oil no more than an aggregate total of 1000 hours during the calendar year.

Because the CTs for this project will have the potential for an aggregate oil-firing total significantly greater than 1,000 hours (up to 5,000 hours) during any calendar year, initial compliance with the applicable YYYY standard must be determined upon startup. Applicability thereafter will be based upon actual aggregate fuel oil use during any calendar year.

Therefore, each new combustion turbine would be subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show compliance with the standard. These operating parameters must be continuously monitored that ensure continuous compliance.

PEF proposes to meet the limit proposed in YYYY of 91 ppbvd. The Department believes the formaldehyde emission limit will be met given the BACT CO limits of 8.0 and 6 ppmvd @15% O_2 for daily and annual operation respectively. It is also expected that the units will easily demonstrate compliance with the formaldehyde limit during the initial and annual test requirements.

7. PERIODS OF EXCESS EMISSIONS

Excess Emissions Prohibited

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

Alternate Standards and Excess Emissions Allowed

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

Startup when the heat recovery steam generator (HRSG) or steam turbine-electrical generator is cold must be performed gradually to prevent thermal damage to the components. The gradual warming of the HRSG and steam turbine components is accomplished by operating the gas turbines for extended periods at reduced loads, which results in higher emissions. The durations are minimized by use of the auxiliary steam generators proposed for the project. In general, the sequences of startup/shutdown are managed by the automated control system.

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

Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases:

- For the very infrequent oil-to-gas and gas-to-oil fuel switching, excess emissions shall not exceed 2 hour in any 24-hour period.

- Steam turbine startups occur as little as once during a ten-year period. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed 8 hours in any 24-hr period. A cold startup of the "steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown lasting at least 48 hours.
- CT/HRSG startups are infrequent but occur more often than steam turbine startups. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed 4 hours in any 24-hr period. A cold startup of a "gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one–hour period. Short startup is enhanced by the use of the auxiliary steam generators that assist in heating surfaces and provide high quality steam for transition piece and nozzle cooling.
- For startup of a CT for the purpose of operation in simple cycle mode, excess emissions shall not exceed 1 hour in any 24-hour period.
- For shutdown, up to three hours of excess emissions are allowed.
- For startup, ammonia injection shall begin as soon as the system reaches the manufacturer's specifications.
- During startup and shutdown, the opacity of the exhaust gases shall not exceed 10%, except for up to ten 6-minute averaging periods in a calendar day during which the opacity shall not exceed 20%. Data for each 6-minute averaging period shall be exclusive from other 6-minute averaging periods.
- Dry Low NO_X combustion systems require initial and periodic "tuning" to account for changing ambient conditions, changes in fuels and normal wear and tear on the unit. Tuning involves optimizing NO_X and CO emissions, and extends the life of the unit components. During tuning, it is possible to have elevated emissions while collecting emission data used in the tuning process. However, the duration of data collection is relatively short, and once tuned, the gas turbine emissions will be minimized. A major tuning session would typically occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar event. Other minor tuning sessions are expected to occur periodically on an as needed basis between major tuning sessions. The permit will require notification prior to any tuning session.

While CO and NO_X emissions during warm and cold startups are greater than during full load steady-state operation, such startups are infrequent. Also, it is noted that such startups would be preceded by shutdowns of at least 24 or 48 hours. Therefore, the startup emissions would not cause annual emissions greater than the potential emissions under continuous operation.

8. BACT DETERMINATIONS FOR THE AUXILIARY BOILER

One gas-fired auxiliary boiler is required for the combined cycle unit system. The primary purpose of the auxiliary boiler is to assist in combined cycle startup by providing steam for combustor cooling until steam of sufficient quality can be provided by the HRSG.

The specifications for the auxiliary boiler are as follows:

- Nebraska Boiler or equivalent;
- Usage of up to 1,000 hours per year;

- Maximum heat input rate of 99 mmBtu/hr heat input; and
- Steam capacity: 85,000 lb/hr.

A recent BACT determination was conducted for the Port Westward, Oregon project. An auxiliary boiler was required for startup of an M501G combined cycle unit. A 91 MMBtu auxiliary boiler was specified for that project.

The state of Oregon conducted a search of BACT determinations in the RACT/BACT/LAER Clearinghouse (RBLC) in early 2005. Approximately 20 RBLC determinations were reviewed by the State of Oregon for auxiliary boilers in the range of 10 to 100 MMBtu/hr that are used in support of combined cycle projects. Separate tables were developed for CO and VOC as well as NO_X, SO_2, and PM/PM_{10}.

The ranges from the Oregon survey are presented in the following table along with limits from other projects for which the auxiliary boiler limits are known. Emissions performance estimates provided by PEF for the auxiliary boiler are included for comparison. NSPS and NESHAP requirements that are applicable to the auxiliary boilers are also included.

Table 8. CO and VOC Standards – Auxiliary Boilers for Combined Cycle Units

Project Location	**CO (lb/MMBtu)**	**VOC lb/MMBtu**
RBLC Survey	0.016 – 0.15	0.004 – 0.018
Port Westward, OR	0.08	0.005
Sithe Mystic, MA	0.08	0.008
Sithe Fore River, MA	0.08 and 100 ppm @3% O_2	0.008/0.004 (NG/FO)
Covert Generating, MI		
Progress Bartow (Application)	**0.08**	**0.01**
NSPS Subpart Dc	Boilers between 10 and 100 mmBtu/hr - Record Keeping Required	
NESHAP Subpart DDDD	400 ppm@3% O_2	

Notes: NG = Natural Gas FO = Fuel Oil

The CO and VOC performance values submitted by PEF for this project are similar to the projects in the Oregon survey and the other combined cycle projects listed above. The auxiliary boiler for this project will be used for the same purpose as those in the other projects.

The Department will set a CO BACT limit of 0.08 lb/MMBtu and operation of no more than 1,000 hours per year for the auxiliary boiler. The Department believes this is at least as stringent as, and possibly more stringent than, the applicable NESHAP standard of 400 ppm @ 3% O_2. This value can be achieved by numerous suppliers by good combustion techniques without resorting to catalysts. In a recent BACT determination conducted by the Washington State Energy Facility Site Evaluation Council for a similar unit, cost effectiveness for CO oxidation catalyst was estimated to be $16,227 per ton of CO. Emissions of VOC from the auxiliary boiler are estimated by PEF to be less than 0.5 TPY. A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC.

9. BACT DETERMINATIONS FOR NATURAL GAS-FIRED FUEL HEATERS

Five fuel heaters are required for the project. The purpose of these units is to heat natural gas above dew point temperatures and prevent condensation. The fuel heaters will be fired with natural gas only.

PEF included, as an example, specifications for the gas heaters as follows:

- Hannover Compression Company or equivalent;
- Continuous use although actual use will be much less; and
- Maximum heat input rate of 3 MMBtu/hr heat input.

Table 9. PEF Emission Estimates from Each Natural Gas-fired Fuel Heater

SO_2	NO_X	CO	VOC	PM
2 gr/100 SCF	100 lb/MMscf	84 lb/MMscf	5.5 lb/MMscf	1.9 lb/MMscf

Small gaseous fuel process heaters ($\leq$ 10 MMBtu/hr) are not subject to Subpart DDDDD. Annual emissions from all 5 heaters of CO and VOC are estimated by PEF to be 5.3 and 0.35 tons per year respectively.

The BACT limit for the fuel heaters will be the same as the auxiliary boiler: 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit will ensure low emissions of VOC. Hours of operation are not limited.

10. BACT DETERMINATIONS FOR THE EMERGENCY FIRE PUMP ENGINE

Progress proposes a 300 HP Clarke/John Deere diesel emergency fire pump. Such engines are regulated under 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

The standards vary depending on the size of the engine. The standards for engines from model year 2007 are given in the following table that are applicable to the emergency engine proposed for this project:

Table 10. EPA Emergency Fire Pump Standards, grams/bhp-hr

Size (hp)	CO	NMHC+NO_X	PM
175 and greater	2.6	7.8	0.40

Notes: bhp = brake horse power NMHC non-methane hydrocarbons

The Department's BACT for this emergency fire pump is compliance with the NSPS standards and use of 0.05% sulfur fuel oil.

11. AIR QUALITY IMPACT ANALYSIS

Introduction

The proposed project will increase emissions of two pollutants at levels in excess of PSD significant amounts: CO and VOC. CO is a criteria pollutant and has AAQS, significant impact levels and de minimis monitoring levels defined for it. There are no applicable PSD increments, AAQS, significant impact or de minimis monitoring levels for VOC. VOC is an ozone precursor and any net increase of 100 tons per year requires an ambient impact analysis including the gathering of preconstruction ambient air quality data.

Major Stationary Sources in Pinellas County

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

Table 11. Largest Sources of NO_X in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	4210
Progress Energy	***Bartow Power Plant (proposed repowering)***	***3191***
Pinellas Board of Co Comm.	Pinellas Co Resource Recovery Facility	1447
Florida Power/Progress	Bayboro Power Plant	337
Florida Power/Progress	Higgins Plant	151

Table 12. Largest Sources of SO_2 in Pinellas County (2005)

Owner	Site Name	TPY
Progress Energy	Bartow Power Plant (before repowering)	16,462
Progress Energy	***Bartow Power Plant (proposed repowering)***	***466***
Pinellas County	Pinellas County Resource Recovery Facility	39

Table 13. Largest Sources of PM in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	Bartow Power Plant (before repowering)	495
Progress Energy	***Bartow Power Plant (proposed repowering)***	***413***
Pinellas County	Pinellas County Resource Recovery Facility	33
Progress Energy	Bayboro Power Plant	4

Table 14. Largest Sources of CO in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***938***
Progress Energy	Bartow Power Plant (before repowering)	369
Pinellas County	Pinellas County Resource Recovery Facility	121
Progress Energy	Higgins Plant	39

Table 15. Largest Sources of VOC in Pinellas County (2005)

Owner	Site Name	Tons per year
Progress Energy	***Bartow Power Plant (proposed repowering)***	***145***
Cardinal Health	Cardinal Health PTS, LLC	110
Hydro Spa	Hydro Spa – Clearwater	60
Times Publishing Co.	St. Pete Times Printing Plant	58
Progress Energy	Bartow Power Plant (before repowering)	57
Lifoam Industries	Lifoam Industries	54

Air Quality and Monitoring in Pinellas County

Pinellas County Department of Environmental Management operates twenty-three monitors at fourteen sites measuring PM_{10}, $PM_{2.5}$, ozone, CO, NO_2, lead, toxics and SO_2. The 2006 monitoring network is shown in the figure below.

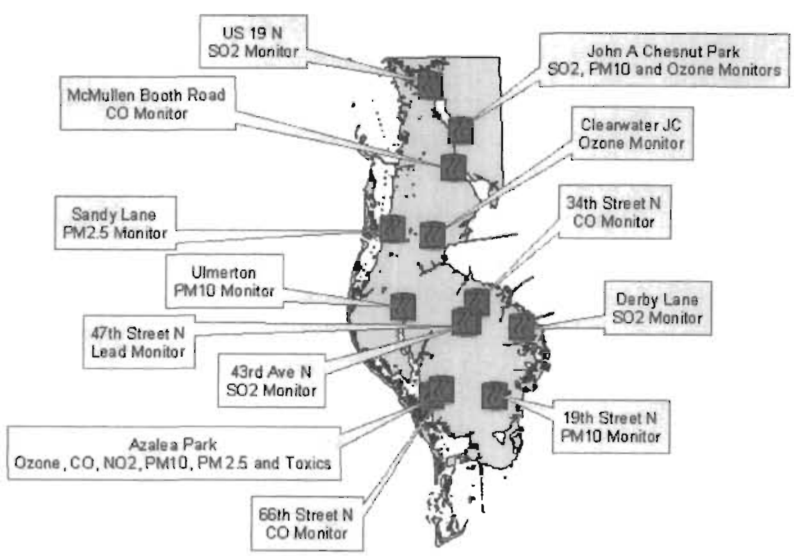

Figure 12. Pinellas County DEM Ambient Air Monitoring Network

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

Table 16. Ambient Air Quality in Pinellas County Nearest to Project Site (2005)

Pollutant	Location	Averaging Period	Ambient Concentration				
			High	2nd High	Mean	Standard	Units
PM_{10}	Ulmerton	24-hour	44	40		150 [a]	ug/m^3
		Annual			21	50 [b]	ug/m^3
SO_2	Derby Lane	3-hour	75	59		500 [a]	ppb
		24-hour	32	24		100[a]	ppb
		Annual			3	20 [b]	ppb
NO_2	Azalea Park	Annual			8	53 [b]	ppb
CO	34th Street N	1-hour	3	3		35 [a]	ppm
		8-hour	2	2		9 [a]	ppm
Ozone	Clearwater JC	1-hour	.090	.088		0.12 [C]	ppm
		8-hour	.076	.074		0.08 [C]	ppm

* The Mean does not satisfy summary criteria due to missing data.
a - Not to be exceeded more than once per year
b - Arithmetic mean
c - Not to be exceeded on more than an average of one day per year over a three-year period

The highest measured values of all pollutants are all less than the respective National Ambient Air Quality Standards (NAAQS). Based on local emission trends, it is not likely that ground-level concentrations will approach the NAAQS levels, at least at the monitoring locations. One exception is ozone because it is formed from precursors (NO_X and VOC) that are available from local industrial and transportation emissions. The tendency to form ozone is accentuated by hot ambient temperature, solar insulation, high pressure, and relatively low wind speed.

Air Quality Impact Analysis

Significant Impact Analysis

Significant Impact Levels (SILs) are defined for CO. A significant impact analysis is performed on this pollutant to determine if the proposed project can cause an increase in ground level concentrations greater than the SILs for CO. The applicant also performed a significant impact analysis for the Class II area for other PSD pollutants that will decrease as a result of the project or increase by values less than their respective significant emission Rates (SERS). The pollutants are SO_2, PM_{10} and NOX. The additional analysis was performed to ensure compliance with National Ambient Air Quality Standards.

In order to conduct a significant impact analysis, the applicant uses the proposed project's emissions at worst load conditions as inputs to the models. The models used in this analysis and any required subsequent modeling analyses are described below. The highest predicted short-term concentrations and highest predicted annual averages predicted by this modeling are compared to the appropriate SILs for the PSD Class II Areas (everywhere except the Chassahowitzka National Wildlife Refuge).

For the Class II analysis a combination of fence line, near-field and far-field receptors were chosen for predicting maximum concentrations in the vicinity of the project. The fence line receptors consisted of discrete Cartesian receptors spaced at 50-meter intervals around the facility fence line. The remaining receptor grid consisted of densely spaced Cartesian receptors at 100 meters apart starting at the property line and extending to 2 kilometers. Beyond 2 kilometers, Cartesian receptors with a spacing of 250 meters were used out to 4 kilometers from the facility. From 4 to 6 kilometers, Cartesian receptors with a spacing of 500 meters were used. From 6 to 10 kilometers, Cartesian receptors with a spacing of 1000 meters were used.

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

The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) for Phase I (2 combustion turbines in simple cycle mode). The applicant's initial PM/PM_{10}, CO, NO_X, and SO_2 air quality impact analyses for this project indicated that maximum predicted impacts from all pollutants are less than the applicable SILs for the Class II area (i.e. all areas except CNWR) except for non-PSD SO_2, 24-hour PM_{10} and NOx for Phase 2 (4 combustion turbines in combined cycle mode, 1 simple cycle). These values are tabulated in the tables below and are compared with existing ambient air quality measurements from the local ambient monitoring network.

Table 17. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase I

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	0.2	1	8	60	NO
	24-Hour	4.7	5	83	260	NO
	3-Hour	14	25	195	1300	NO
PM_{10}	Annual	0.1	1	21	50	NO
	24-Hour	3.5	5	44	150	NO
CO	8-Hour	17.9	500	2,300	10,000	NO
	1-Hour	39.7	2000	3,450	40,000	NO
NO_2	Annual	0.5	1	15	100	NO

It is clear that maximum predicted impacts from the project are much less than the respective AAQS and the baseline concentrations in the area for Phase I. SO_2, PM_{10}, CO and NO_X are also less than the respective significant impact levels that would otherwise require more detailed modeling efforts.

Table 18. Maximum Projected Air Quality Impacts from Progress Bartow for Comparison to the PSD Class II Significant Impact Levels – Phase II

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)	Baseline Concentrations – 2005 Data (ug/m^3)	Ambient Air Standards (ug/m^3)	Significant Impact?
SO_2	Annual	2	1	8	60	YES
	24-Hour	29	5	83	260	YES
	3-Hour	80	25	195	1300	YES
PM_{10}	Annual	0.9	1	21	50	NO
	24-Hour	24	5	44	150	YES
CO	8-Hour	108	500	2,300	10,000	NO
	1-Hour	153	2000	3,450	40,000	NO
NO_2	Annual	5	1	15	100	YES

Maximum predicted impacts from the project for CO (PSD pollutant) are much less than the respective AAQS and the baseline concentrations in the area for Phase II. However, maximum predicted impacts from the project for SO_2, PM_{10} and NOx (non-PSD) are much greater than the SILs but still much lower than the respective AAQS in the area for Phase II. CO is also less than the respective significant impact levels that would otherwise require more detailed modeling efforts. Although SO_2, PM_{10} and NOx are not subject to PSD and the project will ultimately improve air quality in the County with regards to these pollutants, the applicant provided further, more detailed multi-source modeling to ensure compliance with PSD Increments and National and State Ambient Air Quality Standards.

Preconstruction Ambient Monitoring Requirements

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

Table 19. Maximum Air Quality Impacts for Comparison to the De Minimis Ambient Impact Levels.

Pollutant	Averaging Time	Max Predicted Impact (ug/m^3)	De Minimis Level (ug/m^3)	Baseline Concentrations (ug/m^3)	Impact Greater Than De Minimis?
CO	8-hour	108	575	2,300	NO

There are no ambient standards or *de minimus* air quality levels associated with VOC, which is a precursor for the pollutant ozone. The impacts of VOC emissions on ozone levels are not usually seen locally, but contribute to regional formation of ozone. Projects with VOC emissions greater than 100 tons per year are required to perform an ambient impact analysis for ozone including the gathering of preconstruction ambient air quality data. The applicant estimated annual potential net VOC emissions from the repowering project to be 88 tons per year. Therefore, preconstruction monitoring for ozone is not required.

Based on the preceding discussions, the only additional detailed air quality analyses required by the PSD regulations for this project is the following:

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

Models and Meteorological Data Used in the Air Quality Analysis

PSD Class II Area: The AERMOD modeling system was used to evaluate the pollutant emissions from the proposed project in the surrounding Class II Area. AERMOD was approved by the EPA November 2005 and will officially replace the ISCST3 model December 2006. During this "transition" time period from November 2005 to December 2006, both the ISCST and AERMOD model may be used. This "transition" will allow applicants and the Department to assimilate AERMOD guidance and procedures.

The AERMOD modeling system incorporates air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including the treatment of both surface and elevated sources, and both simple and complex terrain. AERMOD contains two input data processors, AERMET and AERMAP. AERMAP is the terrain processor and AERMET is the meteorological data processor.

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

AERMET Meteorological data prepared by the Department and used in the AERMOD model consisted of a concurrent 5-year period of hourly surface weather observations from the Tampa International Airport and twice-daily upper air soundings from the National Weather Service at Ruskin. The 5-year period of meteorological data was from 2001 through 2005. These stations were selected for use in the study because they are the closest primary weather stations to the study area and are most representative of the project site. The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling.

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

PSD Class I Area: The California Puff (CALPUFF) dispersion model was used to evaluate the pollutant emissions from the proposed project in the Class I CNWR beyond 50 km from the proposed project. Meteorological data used in this model was from 2001 through 2003.

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

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

Multi-source PSD Class II Increment Analysis

The PSD increment represents the amount that new sources in an area may increase ambient ground level concentrations of a pollutant from a baseline concentration. The maximum predicted Class II area impacts from this project and all other increment-consuming sources in the vicinity of the Bartow Power Plant are shown in the following table.

Table 20. PSD Class II Increment Analysis (not required, pollutants not subject to PSD)

Pollutant	Averaging Time	2nd Highest-High All Sources Max Predicted Impact (μg/m³)	Allowable Increment (μg/m³)	Impact Greater Than Allowable Increment?
PM_{10}	24-hour	24	30	NO
PM_{10}	Annual	0.3	17	NO
SO_2	24-hour	36	91	NO
SO_2	3-hour	93	`512	NO
SO_2	Annual	0	20	NO
NOx	Annual	3	25	NO

AAQS Analysis

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

Table 21. Ambient Air Quality Impacts (Background Highest of 2004-05)

Pollutant	Averaging Time	Major Sources Impact (ug/m^3)	Background Conc. (ug/m^3)	Total Impact (ug/m^3)	Total Impact Greater Than AAQS?	Florida AAQS (ug/m^3)
PM_{10}	24-hour	27.4	80	107	NO	150
PM_{10}	Annual	2.2	29	32	NO	50
SO_2	24-hour	137	86	223	NO	260
SO_2	3-hour	464	267	731	NO	1300
SO_2	Annual	24	5	29	NO	60
NO_2	Annual	8	17	25	NO	100

Ozone

Ozone is an area-wide pollution problem and the solution to reducing ozone levels is broad-based local and regional reductions in NO_X and VOC emissions (the precursors to ozone formation).

The Bartow Repowering Project will have net reductions of 852 TPY of NO_X. Less than 100 TPY of VOC will be added, which is an increase of less than 1% in the region. Although a minimal amount of VOC will be added, the reduction of NOx should have a positive result in reducing total ozone in the area.

In the near future, many existing power plants and other industries in Florida that contribute to visibility impairment will reduce emissions of NO_X and SO_2 pursuant to the Clean Air Interstate Rule (CAIR) and the requirements of Best Available Retrofit Technology (BART). These NOx reductions will also contribute to decreasing ozone formation.

Additional Impacts Analysis

Impact on Soils, Vegetation, and Wildlife:

Substantial net emissions reductions for sulfuric acid mist, SO_2, PM_{10} and NO_X will help ameliorate past air pollution effects on soils, vegetation and wildlife.

The maximum ground-level concentrations predicted to occur for CO as a result of the proposed project will be considerably less than the respective AAQS. According to the applicant, plant species most sensitive to CO showed cellular damage when exposed to 685,000 micrograms per cubic meter of CO. The applicant modeled CO impacts in the Chassahowitzka Class I area. The highest modeled impact from the proposed repowering was 3.44 micrograms per cubic meter of CO.

As part of the Additional Impact Analysis, Air Quality Related Values (AQRV) are evaluated with respect to the Class I area. This includes the analysis of sulfur and nitrogen deposition. Clearly, with net reductions of sulfur and nitrogen, the deposition of pollutant from Bartow in the Class I area will be less than current levels.

Impact on Visibility:

There will be significant visibility improvements in the immediate vicinity because of the reduction of particulate emissions from the repowered plants and the very significant reductions in condensable and fine particulate precursors. The existing units are subject to opacity limitations of 40 percent under present normal operation whereas the replacement units will be subject to a 10% opacity standard.

Regional Haze in the Chassahowitzka National Wildlife Refuge will experience some improvement as well due to reduced emissions of ozone precursors and fine particulate precursors.

Growth-Related Impacts Due to the Proposed Project:

There will be short-term increases in the labor force to construct the project. According to the applicant, about 300 additional workers will be needed over the 31-month construction period. These temporary increases will not result in significant commercial and residential growth near the project. Operation of the new facility will require no new permanent employees, which will cause no impact on the local area.

Growth-Related Air Quality Impacts since 1977:

According to the applicant, there has been little growth in the area of the Bartow facility since 1977. However, according to the Census, the population of Pinellas County has increased from 728,531 in 1980 to 921,482 in 2000. In 2000, Pinellas County was the most densely populated county in Florida. Despite population growth, the air quality has remained fairly constant. The chart below shows the Air Quality Index, an index of daily air quality, for Pinellas County over twelve years. With the exception of a few years around 1990, the index has remained close to 300 "Good" days while experiencing no days in the "Unhealthy" categories despite a growth of approximately 80,000 people.

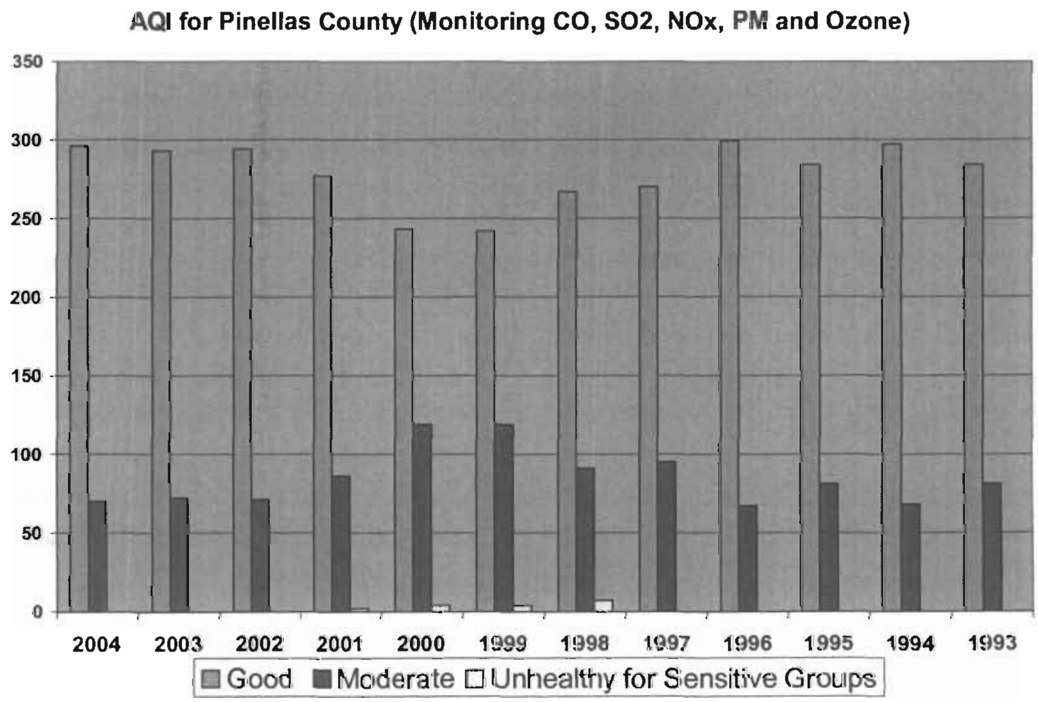

Figure 13. Pinellas County Air Quality Index History.

12. PRELIMINARY DETERMINATION

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

Deborah Nelson is the project meteorologist responsible for reviewing and validating the air quality impact analysis. She may be contacted at deborah.nelson@dep.state.fl.us and 850-921-9537. Teresa Heron is responsible for reviewing the application, and preparing the draft permit. She may be contacted at teresa.heron@dep.state.fl.us and 850-921-9529. Alvaro Linero is the project engineer responsible for preparing the draft BACT determination. He may be contacted at alvaro.linero@dep.state.fl.us and 850-921-9523.

References

[1] Technical Progress Report. Castaldini, C., CMC-Engineering. *Guidelines for Combustor Dynamic Pressure Monitoring,* EPRI, Palo Alto, CA, 2004. Product ID: 1005036

[2] Paper. Xia, J., et al. SGT6-5000F (W501F) Engine Enhancements to Improve Operational Flexibility. POWER-GEN International 2005. Las Vegas, Nevada. December 6-8, 2005.

[3] Test Report. Cubix Corporation. Initial Compliance Test Report for Natural Gas Fueled Stack Emissions on Westinghouse 501F Combined Cycle Turbines. Power Block 1 – PEF Hines Energy Complex Power Block 1. February 1999.

[4] Letter. FDEP to PEF. P.L. Bartow Power Plant Repowering Project - Request for Additional Information. August 30, 2006.

[5] Response Letter. PEF to FDEP. P.L. Bartow Power Plant Repowering Project - Request for Additional Information. September 29, 2006.

[6] Response Letter. PEF to FDEP. Hines Energy Complex. Title V Permit Revision. August 31, 2006.

[7] Paper. Xia, J., et al. SGT6-5000F (W501F) Engine Enhancements to Improve Operational Flexibility. POWER-GEN International 2005. Las Vegas, Nevada. December 6-8, 2005.

[8] Test Report. Cubix Corporation. Initial Compliance Test Report for No. 2 Fuel Oil Fueled Stack Emissions on Westinghouse 501F Combined Cycle Turbines. Power Block 1 – PEF Hines Energy Complex Power Block 1. May 1999.

[9] Letter. Waters, G.D., Gulf Power to Halpin, M.P., FDEP. Lansing Unit Units 4 & 5 Test Results. May 6, 2001.

[10] Report. U.S. Department of Energy, Annual Energy Outlook 2007 (Early Release), Report #DOE/EIA-0383(2007), released December 2007. http://www.eia.doe.gov/oiaf/aeo/index.html

[11] Final Rule. National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Federal Register / Vol. 69, No. 44 / Friday, March 5, 2004. Pages 10512 – 10548.

[12] Proposed Rule. National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. Federal Register Vol. 69, No. 67, April 7, 2004. Pages 18327 – 18343.

CONTENTS

CITATION FORMATS

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-317

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
"317" 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 CRF 60.7]

Means: Title 40, Part 60, Section 7

GENERAL PROVISIONS, SUBPART A FOR NSPS AND NESHAP

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

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

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

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

BACT DETERMINATION

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

Department's DRAFT BACT Summary for Combustion Turbines and Duct Burners

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

Pollutant	Fuel	Method of Operation [a]	Stack Test, 3-Run Average		CEMS [c] Block Average
			ppmvd @ 15% O_2	lb/hr [b]	ppmvd @ 15% O_2
Unit 4 HRSG Stacks					
CO	Oil	CT	8.0	40.4	8.0, 24-hr [d] 6, 12-month [f]
	Gas	CT	4.1	20.8	
		CT & DB	7.6	38.3	
VOC [e,g]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	
		CT & DB	1.5	3.8	
Unit 5CT and Unit 4 Bypass Stacks					
CO	Oil	CT	8.0	40.4	Not Applicable
	Gas	CT	4.1	20.8	
VOC [e]	Oil	CT	2.8	7.6	Not Applicable
	Gas	CT	1.2	3.0	

a. CT means operation of a combustion turbine (CT) in simple cycle or in combined cycle without use of the duct burner (DB). CT & DB means operation in combined cycle mode and using the DB.

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

c. CEMS for CO are required only on the HRSG stacks. Other than startup, shutdown, fuel switching or documented malfunction the CT shall operate above 70% load during simple cycle operation.

d. Compliance with the continuous 24-hour CO standards shall be demonstrated based on data collected by the required CEMS on the HRSG stacks. The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments may also be used to demonstrate compliance with the individual standards for natural gas, fuel oil, or duct burner modes. Separate CO tests shall be conducted under simple cycle mode on the CT stacks.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A on the HRSG stacks and, under simple cycle mode, on the CT stacks. Optionally, EPA Method 18 may also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Rolling Average. Enforcement discretion may be exercised for up to 12 months with respect to the 6 ppmvd @15% O_2 limit for any CT/Duct-fired HRSG upon notification by the permittee of intent to install oxidation catalyst. The permittee shall have 12 months to complete the oxidation catalyst installation. From time of notification to installation of the catalyst all partial or complete calendar months shall be excluded from the 12-month rolling average.

g. Compliance with the CO CEMS based limits shall be deemed as compliance with the VOC limit.

Given the 24-hour and annual BACT CO limits, it is reasonable to expect that formaldehyde emissions will be less than 0.091 ppmvd @15% O_2. This value is equal to the applicable formaldehyde limit of Part 63, Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (CT MACT). Siemens test data supplied by the applicant includes values less than 0.006 ppmvd @15% O_2 for the F class engine at base load without an oxidation catalyst.

Department's DRAFT BACT Summary for Auxiliary Boiler and Gas Heaters

The CO BACT limit for the fuel heaters and the auxiliary boiler is 0.08 lb CO/MMBtu (equates to approximately 84 lb CO/MMscf). A requirement for the exclusive use of natural gas and a 10 % opacity limit is BACT for VOC.

Department's DRAFT BACT Summary for Emergency Fired Pump

The Department's BACT for the emergency fire pump (175 HP or greater) is compliance with the NSPS standards for CO and VOC and use of 0.05% sulfur fuel oil.

GENERAL CONDITIONS

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

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

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

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

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

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

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

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

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

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

13. This permit also constitutes:

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

COMMON CONDITIONS

{Permitting Note: Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at the 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. This regulation does not impose a specific testing requirement. [Rule 62-296.320(4)(b)1, F.A.C.]
9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

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

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

    a. *Required Sampling Time.* Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.
    b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule or test method, the minimum sample volume per run shall be 25 dry standard cubic feet.
    c. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

    a. *Required Equipment.* The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
    b. *Accuracy of Equipment.* Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

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

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

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

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

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

test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

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

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

NSPS SUBPART Dc PROVISIONS

A 99 MMBTu/hr (85,000 lb/hr) auxiliary boiler will serve the combined cycle unit system to produce steam during start up of the CTs. The auxiliary boiler is regulated as Emissions Unit 014. The provisions of this Subpart may be provided in full upon request.

{Note: Only applicable definitions have been included.}

§ 60.40c Applicability and delegation of authority.

(a) Except as provided in paragraph (d) of this section, the affected facility to which this subpart applies is each steam generating unit for which construction, modification, or reconstruction is commenced after June 9, 1989 and that has a maximum design heat input capacity of 29 megawatts (MW) (100 million Btu per hour (Btu/hr)) or less, but greater than or equal to 2.9 MW (10 million Btu/hr).

(b) In delegating implementation and enforcement authority to a State under section 111(c) of the Clean Air Act, § 60.48c(a)(4) shall be retained by the Administrator and not transferred to a State.

(c) Steam generating units which meet the applicability requirements in paragraph (a) of this section are not subject to the sulfur dioxide (SO2) or particulate matter (PM) emission limits, performance testing requirements, or monitoring requirements under this subpart (§ 60.42c, 60.43c, 60.44c, 60.45c, 60.46c, or 60.47c) during periods of combustion research, as defined in § 60.41c.

(d) Any temporary change to an existing steam generating unit for the purpose of conducting combustion research is not considered a modification under § 60.14.

§ 60.41c Definitions.

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

Annual capacity factor means the ratio between the actual heat input to a steam generating unit from an individual fuel or combination of fuels during a period of 12 consecutive calendar months and the potential heat input to the steam generating unit from all fuels had the steam ch a separate source (such as a stationary gas turbine, internal combustion engine, or kiln) provides exhaust gas to a steam generating unit.

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

Natural gas means (1) a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane, or (2) liquefied petroleum (LP) gas, as defined by the American Society for Testing and Materials in ASTM D1835-86, 87, 91, or 97, "Standard Specification for Liquefied Petroleum Gases" (incorporated by reference -- see § 60.17).

Steam generating unit means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.

§ 60.42c Standard for sulfur dioxide.

§ 60.43c Standard for particulate matter.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide.

§ 60.45c Compliance and performance test methods and procedures for particulate matter.

§ 60.46c Emission monitoring for sulfur dioxide

§ 60.47c Emission monitoring for particulate matter.

§ 60.48c Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by § 60.7 of this part. This notification shall include:

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

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

(4) Notification if an emerging technology will be used for controlling SO2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of § 60.42c(a) or (b)(1), unless and until this determination is made by the Administrator.

(g) The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day.

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

(j) The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the Administrator and shall be postmarked by the 30th day following the end of the reporting period.

On July 6, 2006, EPA published the final NSPS Subpart KKKK (40 CFR 60) provisions for combustion turbines in the Federal Register. Although not yet adopted by Rule 62-204.800(8), F.A.C., the combustion turbines shall comply with the applicable federal requirements. These combustion gas turbines are regulated as Emissions Units 009, 010, 011, 012 and 013.

Source: Federal Register dated 7/6/06

Introduction
60.4300 What is the purpose of this subpart?

Applicability
60.4305 Does this subpart apply to my stationary combustion turbine?
60.4310 What types of operations are exempt from these standards of performance?

Emission Limits
60.4315 What pollutants are regulated by this subpart?
60.4320 What emission limits must I meet for nitrogen oxides (NOX)?
60.4325 What emission limits must I meet for NOX if my turbine burns both natural gas and distillate oil (or some other combination of fuels)?
60.4330 What emission limits must I meet for sulfur dioxide (SO2)?

General Compliance Requirements
60.4333 What are my general requirements for complying with this subpart?

Monitoring
60.4335 How do I demonstrate compliance for NOX if I use water or steam injection?
60.4340 How do I demonstrate continuous compliance for NOX if I do not use water or steam injection?
60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
60.4355 How do I establish and document a proper parameter monitoring plan?
60.4360 How do I determine the total sulfur content of the turbine's combustion fuel?
60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
60.4370 How often must I determine the sulfur content of the fuel?

Reporting
60.4375 What reports must I submit?
60.4380 How are excess emissions and monitor downtime defined for NOX?
60.4385 How are excess emissions and monitoring downtime defined for SO2?
60.4390 What are my reporting requirements if I operate an emergency combustion turbine or a research and development turbine?
60.4395 When must I submit my reports?

Performance Tests
60.4400 How do I conduct the initial and subsequent performance tests, regarding NOX?
60.4405 How do I perform the initial performance test if I have chosen to install a NOX-diluent CEMS?
60.4410 How do I establish a valid parameter range if I have chosen to continuously monitor parameters?
60.4415 How do I conduct the initial and subsequent performance tests for sulfur?

Definitions
60.4420 What definitions apply to this subpart?

Table 1 to Subpart KKKK of Part 60-Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

The combustion gas turbines are subject to the applicable requirements of the 40 CFR 63, Subpart YYYY. The provisions of this Subpart may be provided in full upon request. These combustion gas turbines are regulated as Emissions Unit 009, 010, 011, 012 and 013.

Applicability of NESHAP Subpart YYYY

The Bartow Power Plant is a major source of hazardous air pollutant emissions. As such, the proposed new combustion turbines are subject to NESHAP Subpart YYYY, which became final on March 5, 2004. According to the final rule, each unit is considered a "new lean premix gas-fired stationary combustion turbine". Therefore, each new combustion turbine is subject to an emissions standard for formaldehyde of no more than 91 parts per billion by volume, dry (ppbvd @ 15% O_2). Compliance must be demonstrated by initial and annual performance tests. In addition, acceptable operating parameters must be specified that show continuous compliance with the standard., These operating parameters must be continuously monitored that ensure continuous compliance.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as those proposed for the West County Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

The auxiliary 99 MMBtu/hr boiler and the process heaters are subject to the applicable requirements of this 40 CFR 63, Subpart DDDDD. These emission units are regulated as E.U. 014 and 015 respectively. The provisions of this Subpart may be provided in full upon request.

Source: Federal Register Dated 9/12/04

Tables to Subpart DDDDD of Part 63
Table 1 to Subpart DDDDD of Part 63--Emission Limits and Work Practice Standards
Table 2 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Particulate Matter Emission Limits
Table 3 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Mercury Emission Limits and Boilers and Process Heaters That Choose to Comply With the Alternative Total Selected Metals Emission Limits
Table 4 to Subpart DDDDD of Part 63--Operating Limits for Boilers and Process Heaters With Hydrogen Chloride Emission Limits
Table 5 to Subpart DDDDD of Part 63--Performance Testing Requirements
Table 6 to Subpart DDDDD of Part 63--Fuel Analysis Requirements
Table 7 to Subpart DDDDD of Part 63--Establishing Operating Limits
Table 8 to Subpart DDDDD of Part 63--Demonstrating Continuous Compliance
Table 9 to Subpart DDDDD of Part 63--Reporting Requirements
Table 10 to Subpart DDDDD of Part 63--Applicability of General Provisions to Subpart DDDDD (See Appendix B)

Appendices to Subpart DDDDD
Appendix A to Subpart DDDDD--Methodology and Criteria for Demonstrating Eligibility for the Health-Based Compliance Alternatives Specified for the Large Solid Fuel Subcategory
Appendix B to Subpart DDDDD--Applicability of General Provisions to Subpart DDDDD

NSPS REQUIREMENTS FOR STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

The emergency fired pump is subject to the applicable requirements of 40 CFR 60, Subpart IIII. This unit is regulated as emissions unit (E.U.) 017. The provisions of this Subpart may be provided in full upon request.

Source Federal Register Dated 7/11/06. EFECTIVE 9/11/06

Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

What This Subpart Covers
60.4200 Am I subject to this subpart?

Emission Standards for Manufacturers
60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?
60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Emission Standards for Owners and Operators
60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?
60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Fuel Requirements for Owners and Operators
60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

Other Requirements for Owners and Operators
60.4208 What is the deadline for importing and installing stationary CI ICE produced in the previous model year?
60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

Compliance Requirements
60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?
60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

Testing Requirements for Owners and Operators
60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?
60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Notification, Reports, and Records for Owners and Operators
60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

Special Requirements
60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?
60.4216 What requirements must I meet for engines used in Alaska?

60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

General Provisions
60.4218 What parts of the General Provisions apply to me?

Definitions
60.4219 What definitions apply to this subpart?

Tables to Subpart IIII of Part 60
Table 1 to Subpart IIII of Part 60--Emission Standards for Stationary Pre-2007 Model Year Engines with a displacement of < 10 liters per cylinder and 2007-2010 Model Year Engines >2,237 KW (3,000 HP) and with a displacement of < 10 liters per cylinder
Table 2 to Subpart IIII of Part 60--Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE < 37 KW (50 HP) and with a Displacement of < 10 liters per cylinder
Table 3 to Subpart IIII of Part 60--Certification Requirements for Stationary Fire Pump Engines
Table 4 to Subpart IIII of Part 60--Emission Standards for Stationary Fire Pump Engines
Table 5 to Subpart IIII of Part 60--Labeling and Recordkeeping Requirements for New Stationary Emergency Engines
Table 6 to Subpart IIII of Part 60--Optional 3-Mode Test Cycle for Stationary Fire Pump Engines
Table 7 to Subpart IIII of Part 60--Requirements for Performance Tests for Stationary CI ICE with a displacement of >=30 liters per cylinder
Table 8 to Subpart IIII of Part 60--Applicability of General Provisions to Subpart IIII

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

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

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

Reporting period dates: From ____________________ to ______________________

Company: ____

Emission Limitation: ____

Address: ____

Monitor Manufacturer: ____

Model No.: ____

Date of Latest CMS Certification or Audit: ________________________

Process Unit(s) Description: ____

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

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

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

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

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

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

Name: ____

Signature: ____ *Date*: ________________

Title: ____

Progress Energy

RECEIVED
OCT 26 2006
BUREAU OF AIR REGULATION

October 24, 2006

Florida Department of Environmental Protection
South Permitting Section
Division of Air Resource Management
2600 Blair Stone Road, MS 5500
Tallahassee, Florida 32399-2400

Attention: Mr. Al Linero, P.E.

RE: **REQUEST FOR ADDITIONAL INFORMATION REGARDING PSD AIR CONSTRUCTION PERMIT APPLICATION**
DEP FILE NO. 1030011-010-AC AND PSD-FL-381
P.L. BARTOW POWER PLANT REPOWERING PROJECT
FACILITY ID No. 1030011

Dear Mr. Linero,

Based on our meeting on October 16, 2006, this correspondence provides the additional information requested by the Florida Department of Environmental Protection (Department or FDEP) concerning the response to the Department's request for additional information, that was submitted by Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF), on September 29, 2006.. Specifically, this letter and attachments serve to document PEF's approach to the "interim operating mode", whereby two CTs will be operated for an interim period prior to retirement of the three existing steam units.

During the interim mode, up to two simple cycle CTs will start up prior to the shut down of the three existing boilers. To avoid PSD applicability during the interim mode (i.e., simple cycle phase), the project will be broken into separate phases, the "interim" and "permanent" phases. Under this scenario, the two new CTs will be permitted as if they are independent of the total project for the "interim" period. In order to avoid PSD applicability, an enforceable emissions cap (just under the PSD applicability threshold) will become a condition of the permit, limiting operations of these units during this period. After these CTs are then "re-commissioned" as part of the "permanent" phase (4-on-1 combined-cycle operation), the interim conditions would go away. As NOx will be limiting pollutant for PSD applicability, PEF proposes to monitor compliance with the NOx CEMS and track and report tons of NOx on a monthly basis.

Attached are revised application forms that reflect this interim mode approach. Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to department requests for additional information of an engineering nature. Therefore, please find attached a signed and sealed P.E. certification accompanying this submittal.

Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733

If you should have any questions regarding this letter and attachments, please don't hesitate to contact Scott Osbourn, P.E. at (813) 287-1717 or me at (727) 820-5962.

Sincerely,

for

Ann Quillian, P.E.
Senior Environmental Specialist

Enclosures

cc: Scott Osbourn, P.E., Golder Associates Inc.
Jim Little, EPA Region IV
John Bunyak, NPS
Mara Nasca, DEP, SW District
Peter Hessling, PCDEM

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 at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also 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
- Where the applicant proposes to establish, revise, or renew a plantwide applicability limit (PAL).

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 & 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: **Bartow Plant**	
3. Facility Identification Number: **1030011**	
4. Facility Location...: Street Address or Other Locator: **1601 Weedon Island Drive** City: **St. Petersburg** County: **Pinellas** Zip Code: **33702**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Ann Quillian, PE**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida, Inc.** Street Address: **100 Central Avenue, MAC 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:	3. PSD Number (if applicable):
2. Project Number(s):	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 construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

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

This application outlines PEF's approach to the "interim operating mode". During the interim mode, up to two simple cycle CTs will start up prior to the shut down of the three existing boilers. To avoid PSD applicability during the interim mode (i.e., simple cycle phase), the project will be broken into separate phases, the "interim" and "permanent" phases. Under this scenario, the two new CTs will be permitted as if they are independent of the total project for the "interim" period. In order to avoid PSD applicability, an enforceable emissions cap (just under the PSD applicability threshold) will become a condition of the permit, limiting operations of these units during this period. After these CTs are then "re-commissioned" as part of the "permanent" phase (4-on-1 combined-cycle operation), the interim conditions would go away. As NOx will be limiting pollutant for PSD applicability, PEF proposes to monitor compliance with the NOx CEMS and track and report tons of NOx on a monthly basis.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
	Two (2) Simple-Cycle F-Class Combustion Turbines	AC1A	

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 : **Rufus Jackson**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **Progress Energy Florida, Inc.** Street Address: **1601 Weedon Island Drive** City: **St. Petersburg** State: **FL** Zip Code: **33702**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(727) 827-6111** ext. Fax: **(727) 827-6102**
4.	Owner/Authorized Representative Email Address: **Rufus.Jackson@pgnmail.com**
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.* Rufus Jackson Signature 10/25/06 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:

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:
   Street Address:
   City: State: Zip Code:

4. Application Responsible Official Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

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.

   ______________________________ ____________________
   Signature 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 St., Suite 114**
   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] 10/20/06

Signature Date

(seal)

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) **343.87** North (km) **3082.69**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/51/41** Longitude (DD/MM/SS) **82/36/6**	
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 : **The project consists of one nominal 1,279 MW power block with four CT/HRSG trains and one simple-cycle CT at an additional 190 MW. See Scope of Application and the PSD report.**			

Facility Contact

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

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: **CTs and HRSG Duct Burners are subject to NSPS 40 CFR 60, Subpart KKKK.** **CTs are subject to NESHAP 40 CFR 63, Subpart YYYY.**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
CO – Carbon Monoxide	**A**	**Y**
NOX – Nitrogen Oxides	**A**	**Y**
PM – Particulate Matter – Total	**A**	**Y**
PM10 – Particulate Matter	**A**	**Y**
SAM – Sulfuric Acid Mist	**A**	**Y**
SO2 – Sulfur Dioxide	**A**	**Y**
VOC – Volatile Organic Compounds	**A**	**Y**

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
PM				**24**	
PM10				**14**	
NOx				**39**	
SO2				**39**	
CO				**99**	
VOC				**39**	
SAM				**6**	

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

As NOx is the limiting pollutant for PSD applicability, NOx CEMS will be used to monitor compliance with the emission cap. Emissions will be tracked and reported as tons of NOx and limited to the 39 ton cap.

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: **PSD Report** ☐ 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: **PSD Report** ☐ 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: ☒ Previously Submitted, Date:____

Additional Requirements for Air Construction Permit Applications

1.	Area Map Showing Facility Location: ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable (existing permitted facility)
2.	Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☐ Attached, Document ID:____
3.	Rule Applicability Analysis: ☒ Attached, Document ID: **PSD Report**
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ Attached, Document ID:____ ☒ Not Applicable (no exempt units at facility)
5.	Fugitive Emissions Identification: ☐ Attached, Document ID:____ ☒ Not Applicable
6.	Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
7.	Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
8.	Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
9.	Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☒ Attached, Document ID: **PSD Report** ☐ 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:_____ ☐ 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:_____ ☐ 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:_____ 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:_____ ☐ 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.

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 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: **Two Siemens Frame F, SGT6-PAC-5000F CTs operating in simple-cycle mode.**

3. Emissions Unit Identification Number: **Unit No. 013**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**12/2006**	**12/2008**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Siemens** Model Number: **SGT6-PAC-5000F**

10. Generator Nameplate Rating: **(See Tables 2-2 and 2-4 of PSD Report)** MW

11. Emissions Unit Comment: **Total nominal capacity of 190 MW each consisting of 2 CTs operating in simple-cycle mode.**

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Distillate Fuel Oil** • **Water injection**	
2. Control Device or Method Code(s): **28**	

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: **(see Appendix Table A-1 and A-7)**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 **8760**hours/year
6. Operating Capacity/Schedule Comment: **Appendix Tables A-1 and A-7 of PSD Report show the maximum heat input at ISO conditions and base load. Appendix A also has performance at various turbine inlet temperatures and loads.**		

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: **See PSD Report**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking: **Exhausts through CT 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: **18**feet
8. Exit Temperature: **See PSD Report**°F	9. Actual Volumetric Flow Rate: **See PSD Report**acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: **See PSD Report**dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)
15. Emission Point Comment: **Tables 2-2 and 2-4 of the PSD Report shows the emission point characteristics at ISO conditions and base load. Appendix A of the PSD Report has emission point characteristics for various turbine inlet temperatures and operating loads.**	

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **20100101**	3. SCC Units: **1,000 Gallons Used**	
4. Maximum Hourly Rate: **13.4**	5. Maximum Annual Rate: **See comment**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Annual fuel rate will be constrained by the NOx TPY emission cap. Million British Thermal Units (Btu) per SCC unit = 129.9 (rounded to 130). Based on 7.1 pounds per gallon (lb/gal); LHV = 18,514 Btu/lb ISO conditions. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Natural Gas**		
2. Source Classification Code (SCC): **20100201**	3. SCC Units: **Million cubic feet**	
4. Maximum Hourly Rate: **1.9**	5. Maximum Annual Rate: **See comment**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **933 LHV**
10. Segment Comment: **Annual fuel rate will be constrained by the NOx TPY emission cap. Based on 933 Btu/cf (LHV); ISO conditions and 8,760 hr/yr operation. See Section 2.0 in PSD Report for fuel usage of other loads and conditions.**		

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
PM_{10}			EL
SO_2			EL
NO_x	028		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**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **24** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See PSD Report, Section 2.0, Tables 2-2 and 2-4, and Appendix A.**	
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 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **24 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 5; if > 400 hrs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0, Table 2-4, and Appendix A.**	

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: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0, Table 2-2, and Appendix A.**	

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: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **See PSD Report** lb/hour **14** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See PSD Report, Section 2.0, Tables 2-2 and 2-4, and Appendix A.**	
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 2

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **14 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 5; if > 400 hrs.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0, Table 2-4, and Appendix A.**	

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: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Annual VE test: EPA Method 9.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0, Table 2-2, and Appendix A.**	

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: **See PSD Report** lb/hour **39** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See PSD Report, Section 2.0, Tables 2-2 and 2-4, and Appendix A.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **Emission factor: 2 grains Sulfur (S) per 100 CF gas; 0.05% S oil. See PSD Report, Section 2.0 and Appendix A.**	

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: **39 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **2 grains/100 SCF**	4. Equivalent Allowable Emissions: lb/hour tons/year
5. Method of Compliance: **Fuel sampling.**	
6. Allowable Emissions Comment (Description of Operating Method): **Natural gas-firing CT. See PSD Report Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **39** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **Natural gas-firing: See PSD Report, Section 2.0 and Appendix A.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **See PSD Report, Section 2.0 and Appendix A.**	

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: **39 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7e; CEM - 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested allowable emissions and units at 15% O_2. Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **15 ppmvd**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 20 and 7e; CEM - 24-hr block average.**	
6. Allowable Emissions Comment (Description of Operating Method): **Requested allowable emissions and units at 15% O_2. Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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.)

<u>**Potential/Estimated Fugitive Emissions**</u>

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: **See PSD Report** lb/hour **99** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See PSD Report, Section 2.0, Tables 2-2 and 2-4, and Appendix A.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **See PSD Report, Section 2.0.**	

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: **99 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load; if > 400 hrs. CEM 24-hr block.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-2**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Method 10; base load. CEM 24-hr block.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Report** lb/hour **39** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **See PSD Report** Reference: **Siemens, 2006; PEF, 2006; Golder, 2006.**	7. Emissions Method Code: **2**
8. Calculation of Emissions: **See PSD Report, Section 2.0, Tables 2-2 and 2-4, and Appendix A.**	
9. Pollutant Potential/Estimated Fugitive Emissions Comment: **See PSD Report, Section 2.0.**	

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: **39 TPY for both CTs**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Oil-firing: See PSD Report, Section 2.0 and Appendix A.**	

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: **See PSD Table 2-2**	4. Equivalent Allowable Emissions: **See PSD** lb/hour **See PSD** tons/year
5. Method of Compliance: **EPA Methods, 18, 25, or 25A; base load.**	
6. Allowable Emissions Comment (Description of Operating Method): **Gas-firing: See PSD Report, Section 2.0 and Appendix A.**	

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 1

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **60** min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment: **FDEP Rule 62-296.320(4)(b)1, F.A.C. requires 20 percent opacity. Excess emissions provided by Rule 62-210.700.**	

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: **not yet identified** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM required pursuant to 40 CFR, Part 75. NO_x monitoring includes diluent monitor (O_2 or CO_2).**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **CO**
3. CMS Requirement:	☐ Rule ☒ Other
4. Monitor Information... Manufacturer: **not yet identified** Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: **CEM monitor anticipated pursuant to previous BACT determinations.**	

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: **PSD Report** ☐ 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: **PSD Report** ☐ 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: **PSD Report** ☐ 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(10) and 62-212.500(7), F.A.C.; 40 CFR 63.43(d) and (e)) ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
2.	Good Engineering Practice Stack Height Analysis (Rule 62-212.400(4)(d), F.A.C., and Rule 62-212.500(4)(f), F.A.C.) ☒ Attached, Document ID: **PSD Report** ☐ Not Applicable
3.	Description of Stack Sampling Facilities (Required for proposed new stack sampling facilities only) ☒ Attached, Document ID: **PSD Report** ☐ 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

Progress Energy

RECEIVED
OCT 02 2006
BUREAU OF AIR REGULATION

September 29, 2006

Mr. A.A. Linero, P.E.
Program Administrator, South Permitting Section
Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5500
Tallahassee, Florida 32399-2400

RE: **REQUEST FOR ADDITIONAL INFORMATION REGARDING PSD AIR CONSTRUCTION PERMIT APPLICATION**
DEP FILE NO. 1030011-010-AC AND PSD-FL-381
P.L. BARTOW POWER PLANT REPOWERING PROJECT
FACILITY ID No. 1030011

Dear Mr. Linero,

This correspondence provides the additional information requested by the Florida Department of Environmental Protection (Department or FDEP) concerning the PSD Air Construction Permit Application that was submitted by Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF), on July 31, 2006. This information is presented in the same sequence as the requested information in the Department's letter to Rufus Jackson, PEF dated August 30, 2006.

Comment 1: Please provide Siemens brochures and information for the CTs. Include heat rate, heat input curves, etc.

Response: Included as Attachment 1 to this response package is a Siemens marketing brochure for gas turbine equipment, representative of the equipment proposed for the Bartow Repowering Project. The brochure provides heat rates for various cases. In addition, heat rate data and heat input data were provided in Appendix A of the air application (Table A-1). Heat input curves were not provided, but values were provided at four reference temperatures which would allow a curve to be constructed. As is typically required by similar previous air permits, PEF will construct the necessary curves and provide to the Department with the initial compliance testing.

Comment 2: Please provide the manufacturer's curves showing expected NOx, CO, VOC and formaldehyde concentrations with respect to CT load as percent of full load.

Response: Siemens has indicated that they do not provide emission "curves" for various loads. However, the tables in Appendix A of the air application provided emission concentration values at various load points for firing on natural gas (100%, 80% and 60% load) and on fuel oil (100%, 80% and 65% load). Finally, manufacturer's data was received for formaldehyde emissions, and is included as Attachment 2.

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

Comment 3: Earlier versions of the Siemens CTs that will be installed at the Bartow Plant have been operating for several years at the Hines Energy Complex in Polk County. The Hines CTs are the previously designated Westinghouse or Siemens-Westinghouse 501F Series. Provide the results of CO and VOC acceptance and compliance tests and any tests conducted at partial loads. Include as well any tests conducted while firing fuel oil.

Response: Initial compliance test results for CO and VOC emissions when firing natural gas or fuel oil are included as Attachment 3 for Hines Power Blocks 1, 2 and 3.

Comment 4: Provide the project estimates for 24-hour CO emission values when operating in: normal gas-fired mode; using the duct burners; power augmentation or peaking if practiced; and fuel oil firing. What kind of 12-month rolling average can be achieved considering all the modes of operation combined? Any CEMS CO information from units at Hines would be useful in this regard although the Siemens CT's might have been improved since construction of the previous versions.

Response: Table 2-7 of the previously submitted air application provided proposed emission concentrations and rates for the combustion turbines in various operating modes. Under the heading for CO, the maximum emissions (both ppmvd at 15% O_2 and lb/hr) are provided for each of the proposed operating modes. It can be assumed that each of the operating modes provided could be attained continuously for a period of 24 hours or more. Therefore, in response to the above question, these values would represent the Project estimates for 24-hour CO emission values when operating in each of the various proposed modes.

In order to determine a potential 12-month rolling average that's representative of proposed operation, Table A-15 of the application would be combined with Table 2-7. Table A-15 provides worst case annual emissions, which are based on the maximum number of proposed operating hours in each mode on an annual basis. By combining the data from these two tables, a worst-case weighted 12-month rolling average of approximately 9.5 ppmvd at 15% O_2 is obtained. Siemens CTs at the Hines Energy Complex operate in only one mode: normal. Hines does not have duct burners nor power augmentation. The fuel oil operation is limited and usually with start-up or shutdown. Therefore, PEF is not including CEMs data as it is not a good representation of the equipment being installed for the Project.

Comment 5: Please update the costs of oxidation catalyst. The Department obtained lower capital cost estimates from suppliers than submitted by applicants during permitting of several recent projects. We can discuss the details to properly frame the assumptions for potential suppliers. Following are some points to consider in the update:

- Typically costs are acknowledged for additional fuel use to account loss of any capacity when using catalyst but not the value of lost electric sales. These aspects of the oxidation catalyst cost-effectiveness estimate should be updated.
- Check to make sure that credit is taken for returning spent catalyst to the supplier.

- Oxidation catalyst typically lasts much longer than three years. A more realistic lifetime should be assumed rather than just assuming that the catalyst requires replacement after three years.
- It would be easy enough to inquire from Seminole Electric how often they have added or changed catalyst on their Siemens-Westinghouse 501F combined cycle units at their Payne Creek Plant.

Response: Oxidation catalyst cost analysis Tables B-3 and B-4 have been updated to reflect vendor quote supplied to FDEP on February 16, 2006 by Engelhard Corporation. These revised tables (B-3 through B-6) are included in Attachment 4. The Department's cost quote was supplied for a Frame 501G unit and has been scaled based on mass flow rate for the Project. The estimated costs associated with this new quote are similar to those presented in the original permit application.

- Per the Department's request, the value of lost electric sales has been removed from the energy costs and the heat rate penalty has been updated to reflect today's natural gas cost of approximately $9.6/MMBtu (see Revised Table B-4 in Attachment 4).
- As reflected in the revised Table B-4, a new CO catalyst is approximately $625,000, of which approximately $565,000 is for the catalyst. The catalyst replacement cost is about $440,000, which would include credit for the return. The difference, or credit, is about $125,000. These are estimates obtained verbally from the vendor.
- Per the Department's request, data from Seminole Electric's Payne Creek facility was reviewed to determine actual life of similar catalyst. Payne Creek data, since initial operation in 2001, indicates approximately 22,375 hours of operation for CT-1 of which a little over 200 hours are oil fired. Similarly, approximately 25,300 hours of operation have been recorded for CT-2, of which 90 hours are oil fired. The catalysts have yet to be replaced. The data spans a 5 year period, however total hours are close to 3 years at 100 percent capacity or 26,280 total hours. As such, this data is not inconsistent with the vendor guarantee of 3 years of full-time operation. In addition the Bartow project proposes as much as 1,000 hours of oil firing per CT per year. If such a level of oil firing was experienced at Payne Creek, the useful catalyst life of the units at that facility would likely have been negatively affected. For these reasons, the 3 year performance guarantee is still considered appropriate for the cost analysis.

Comment 6: Some recognition needs to be given in the oxidation catalyst evaluation for the benefits of VOC and formaldehyde reduction potential.

Response: Formaldehyde emissions are already estimated to be low for this equipment model type (see previous response to Comment 2, as well as Attachment 2) and will be well below the applicable MACT standard of 91 ppb. With respect to VOC emissions, a cost-effectiveness analysis was presented in the previously submitted application (see Section 4.4.3).

Comment 7: Refer to the Interim Project Configuration (Section 2.3, Page 8 of the Application PSD report). Up to two simple cycle CTs will start up prior to the shut down of the three furnaces/boilers. To avoid PSD applicability during the simple cycle phase, creditable emission reductions must be federally enforceable as a practical matter at and after the time that actual construction on the project(s) begins. Also the actual reductions must take place before the date that the emissions increase from any of the new units occurs.

Response: PEF followed the procedures in Rule 62-212.400(2), F.A.C. in assessing whether a significant net emissions increase would result from this project. Specifically, the "baseline actual emissions" were subtracted from the future emissions ("projected actual emissions" for the existing boilers and "potential" emissions for the new CTs) and compared to the significance thresholds. As explained in Section 2.3 of the PSD application, the projected emissions for the first 12 months following the project reflected the interim and permanent project configurations -- two CTs and three boilers operating for the first six months, and only the repowered units operating for the next six. This calculation showed that a significant increase would result for CO and VOC, but not for the remaining PSD pollutants.

As an alternative (and perhaps simpler) approach, PEF suggests that a federally enforceable permit condition limiting its potential emissions of SO2, NOx, PM/PM10 and SAM to baseline levels (plus the significance thresholds) be included in the permit for PSD avoidance during the first 12 months following startup of any of the new CTs. Beyond this initial 12-month period (i.e., after the conclusion of the interim operating period), the operating permit would rely on the other permanent limits to ensure that there is not a significant increase for the permanent configuration. Pursuant to the requirements in Rule 62-212.400(2), F.A.C. and the definitions in Rule 62-210.200, F.A.C., limiting facility-wide potential emissions to baseline levels (plus the significance thresholds) ensures that PSD will not be triggered for SO2, NOx, PM/PM10 and SAM, during the interim project configurations.

Comment 8: The scenario presented in Table 2-2 includes separate 6-month periods. The first 6 months represents operation of the existing boilers. The second 6 months represent combined cycle operation only. However, no emissions scenario is presented when the existing units will be operating concurrently with the one or two simple cycle turbines as described elsewhere in the application. If existing units are operating at the same time with new units, please submit proposed operating emissions scenarios and calculations. Refer to Rule 62-210.200(179)(f) "Net Emissions Increase".

Response: See the response to Comment 7 above.

Comment 9: The project addresses contemporaneous emission increases/decreases related to the three fossil fuel fired steam generators. Pursuant to Rule 62-210.400(2) F.A.C, please assess and if necessary resubmit the emissions netting calculation considering the five year contemporaneous period for this modification and include any other increases or decreases from any other emission unit or project at the facility.

Response: See the response to Comment 7 above. There have not been any contemporaneous increases at this facility.

Comment 10: If any of the pollutants exceed the PSD significant threshold level due to the new calculations, please submit the appropriate BACT analysis for that pollutant. Please refer to Rule 62-212.400 (2)3 -- Hybrid Test for Multiple Types of Emissions Units and to the Rule 62- 210.200 (34) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL"; Rule 62-2 10.200 (1 79) "Net Emissions Increase".

Response: See the response to Comment 7 above.

Comment 11: Submit a milestone chart showing: when each existing boiler is destined to be shut down in 2009; when any CTs will commence operation in simple cycle mode; and when each CT will commence operation in combined cycle mode.

Response: PEF's current estimate of these proposed "milestone dates" is as follows:

- Shutdown of Bartow Unit No.1 - June 2009;
- Shutdown of Bartow Unit No.2 - June 2009;
- Shutdown of Bartow Unit No.3 - June 2009;
- Simple Cycle Operation of 1st CT - Dec 2008;
- Simple Cycle Operation of 2nd CT - Dec 2008; and
- Combined Cycle Operation of all four CTs - June 2009.

Comment 12: Will the hourly potential emissions increase beyond their present potential during any time in 2006? If so, for how long and for which pollutants?

Response: PEF has clarified that the Department meant to refer to the year 2008 in the above question. For the year 2008 and beyond, the hourly potential emissions will not increase beyond their present potential.

Comment 13: Submit tables, timelines or charts showing how each of the requirements of the definition of "Net Emissions Increase" at Section 62-210.200(179) will be met.

Response: The responses provided to the Department's Comments 7, 8, 9, and 11 address this comment.

Comment 14: What is the ammonia slip proposed for this project (ppm)?

Response: The ammonia slip proposed for the project will be less than or equal to 5 ppmvd, corrected to 15 percent O_2.

Comment 15: The application only lists the 5 CTs, 4 HRSGs, one auxiliary boiler and 5 heaters. Would this plant include Cooling Tower, an Emergency Generator and Diesel Fired Pump, or any other ancillary equipment? If so, please provide information about these units.

Response: The only additional auxiliary equipment is a diesel-fired emergency fire pump. This change in the project design occurred after the air application was submitted. This 300 HP Clarke/John Deere engine will meet all requirements of the new NSPS (*Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*), recently promulgated on July 11, 2006 in *Federal Register, Volume 71, Number 132*. Vendor specifications are included in Attachment 5. In addition, revised permit application pages are attached, providing necessary information.

Comment 16: Is there another future phase for this facility's repowering project?

Response: Currently, there is no additional phase of the repowering project other than what is represented in the application. However, as described in the application, this project could be considered to be "phased", as the current plan has two combustion turbines operational (simple-cycle) in December 2008, two additional combustion turbines operational in June 2009 (capable of operating simple-cycle and/or with the two previous CTs in the 4-on-1 combined-cycle configuration), and the fifth combustion turbine (simple-cycle only) that may become operational in conjunction with, or subsequent to the 4-on-1 combined-cycle power block operation.

While these are currently the only additional units planned for the Bartow facility, future needed expansions of the generating capacity are continually being evaluated. These evaluations may determine that the Bartow Plant site is the best location for additional generating resources. Since this is unknown at this time, it is anticipated that any future generation expansion at the site, should it occur, would be handled as a completely separate project and not considered to be a "phase" of the current repowering project.

Comment 17: Section 6-5 of the application states that the "FDEP considers this station (Tampa) to have surface meteorological data representative of the project site." The FDEP can not determine if the Tampa International Airport surface data is representative without further information regarding the surface land use data at the facility. Please provide information to support the conclusion that the Tampa International surface data is most representative for this project.

Response: The general climatology and surface land use in the vicinity of the Tampa International Airport (TPA) are very similar to that found in the vicinity of the proposed Bartow Power Plant project. Because of the very close proximity of the two locations (11 km), the flat terrain between the two sites, and the large water bodies to the west of both sites, the wind frequency distributions at the two sites are expected to be very consistent with one another.

The surface land use features within a 3-km radius of each site were evaluated using the AERSURFACE program which processes surface land use parameters for use in AERMOD. These parameters are used to estimate the surface boundary layer conditions that characterize plume dispersion. These parameters include: albedo, which is an indicator of the mean reflectivity of the land surface; Bowen Ratio, which is an indicator of average moisture conditions; and surface roughness, which is an indicator of the mean obstacle height. For TPA, the 3-km radius was centered on the ASOS meteorological tower. For the Bartow Plant site, the 3-km radius was centered among the project's proposed new stack locations. The average parameter values are as follows:

	Albedo	Bowen Ratio	Surface Roughness (m)
TPA	0.16	0.94	0.57
Bartow	0.11	0.54	0.34
Range	0 to 1.0	0 to >1.0	0 to >1.0 (limited to 1.0 by program)

These results show that the values for albedo, Bowen Ratio, and surface roughness are slightly lower at the Bartow Power Plant site than those at TPA. The lower values at the Bartow Plant site indicate that the site is surrounded by slightly more water and swamp areas than that for TPA. Given that these land use values are similar, it is expected that the differences in processing the meteorological data using the land use around the Bartow Plant site or TPA would not produce significantly different maximum predicted impacts for the project. As such, the general climatology and land use in the vicinity of the proposed project are considered to be very similar to and representative of those in the vicinity at TPA.

Comment 18: Although PM, NO_X and SO_2 are not subject to PSD, the applicant provided a Significant Impact Analysis for these pollutants to conclude compliance with the respective Class I1 Increment. The results of the modeling concluded that the impacts were above the Class II Significant Impact Levels. Therefore, since the impacts are "Significant" and the future stacks will be much lower, the Department requests more detailed modeling to ensure that the Increment and the Ambient Air Quality Standards are not exceeded due to this modification. Please provide a full Increment and AAQS analysis.

Response: More detailed modeling analyses were performed to ensure that the AAQS and PSD Class II increments for PM_{10}, SO_2, and NO_2 are not predicted to be exceeded due to the proposed modification. The AAQS analyses were based on predicting the maximum impacts for the proposed modification and background sources added to a non-modeled background concentration to estimate total air quality impacts. The non-modeled background concentrations are due to sources not explicitly modeled in the analysis and are based on monitoring data. The PSD Class II increment consumption analyses were based on predicting the maximum impacts for the proposed modification and PSD increment consuming and expanding sources.

The air modeling assumptions and procedures used to predict the air quality impacts for these analyses are the same as those used in the application. The AERMOD dispersion model (Version 04300) was used to predict impacts using 5 years of hourly surface weather observations and twice-daily upper air soundings for 2001 to

2005 from the National Weather Service (NWS) offices located at the Tampa International Airport and in Ruskin, respectively. Concentrations were predicted in a Cartesian grid using more than 3,000 receptors that extended from the plant boundary out to 10 km from the site. This area is considered the modeling area.

These analyses were based on modeling the project with the Phase 2 source configuration that assumed four combined cycle combustion turbines and one simple cycle combustion turbine, all firing distillate light oil. For SO_2 and NO_2, the combustion turbines were modeled at maximum load conditions since the maximum impacts for the project were predicted for those conditions. For PM_{10}, the combustion turbines were modeled at 60 percent load conditions since the maximum impacts for the project were predicted for those conditions. In addition, the five natural gas-fired heaters and an auxiliary boiler were included. For the PSD Class II increment consumption analysis for PM_{10} only, the baseline emissions due to Boilers 1, 2, and 3, which are to be retired as a result of the proposed project, were included in the analysis.

Background sources located within 40 km of the site were considered for the air impact analyses. All major facilities within the modeling area (i.e., 10 km from the site) were modeled. Facilities beyond the modeling area and within 40 km of the site were considered to be in the screening area. All facilities in the screening area were evaluated using the *North Carolina Screening Technique*. Based on this technique, facilities whose annual emissions (i.e., TPY) are less than the threshold quantity, Q, are eliminated from the modeling analysis. Q is equal to 20 x (D-10 km), where D is the distance in km from the facility to the Project Site. However, for PM_{10}, additional facilities were modeled since the maximum PM_{10} impacts due to the project alone were relatively close to the 24-hour average PSD Class II increment.

Listings of background PM, SO_2, and NO_2 sources that were used in the AAQS and PSD Class II analyses and their locations relative to the Bartow Power Plant site are provided in Tables 18-1 to 18-3 (see Attachment 6). Data for background sources were obtained from FDEP and were supplemented with current and historical information available within Golder. Detailed background source data that were used for the AAQS and PSD Class II increment analyses are presented in Attachment 6.

The non-modeled background concentrations were estimated from PM_{10}, SO_2, and NO_2 monitoring data collected by the FDEP in Pinellas County based on observations from 2004 and 2005. A summary of these data is presented in Table 18-4. As shown in this table, the measured concentrations are well below the AAQS. The maximum annual average and overall second-highest short-term average concentrations were used to represent the non-modeled background concentration to assess total air quality impacts.

A summary of the results of the cumulative source modeling for demonstrating compliance with the PM_{10}, SO_2, and NO_2 AAQS (i.e., impacts due to sources at the Bartow Power Plant modeled with background sources added to non-modeled background concentrations) are presented in Table 18-5.

As shown in Table 18-5, the maximum 24-hour and annual average PM_{10} concentrations due to the Project and other AAQS sources are predicted to be below the 24-hour and annual AAQS of 150 and 50 $\mu g/m^3$, respectively.

The maximum 3-hour, 24-hour, and annual average SO_2 concentrations due to the Project and other AAQS sources are predicted to be below the 3-hour, 24-hour, and annual AAQS of 1,300; 260; and 60 $\mu g/m^3$, respectively.

The maximum annual average NO_2 concentrations due to the Project and other AAQS sources are predicted to be below the annual AAQS of 100 $\mu g/m^3$.

A summary of the results of the cumulative source modeling for demonstrating compliance with the PM_{10}, SO_2, and NO_2 PSD Class II increments (i.e., impacts due to PSD increment-affecting sources) are presented in Table 18-6.

As shown in Table 18-6, the maximum 24-hour and annual average PM_{10} concentrations due to the Project and other PSD sources are predicted to be below the allowable 24-hour and annual PSD Class II increments of 30 and 17 $\mu g/m^3$, respectively.

The maximum 3-hour, 24-hour, and annual average SO_2 concentrations due to the Project and other PSD sources are predicted to be below the allowable 3-hour, 24-hour, and annual PSD Class II increments of 512, 91, and 20 $\mu g/m^3$, respectively.

The maximum annual average NO_2 concentrations due to the Project and other PSD sources are predicted to be below the allowable PSD Class II increment of 25 $\mu g/m^3$.

Comment 19: Please provide further information regarding the short tern emission rates used in the modeling analysis. For CO, Table 2-1, states that simple cycle operation will emit 154.5 TPY. In Tables 2-3 and 2-5, the CO lb/hr short-term emission rate for simple cycle operation at 59 degrees F is 20.3 lb/hr and 151.3 lb/hr for gas and oil, respectively. Twenty pounds per hour for 7,760 hours on gas and 151.3 lb/hr for 1,000 hours on oil equates to 154.5 TPY, which is a long term emission rate. For modeling purposes, the worst-case scenario should be used. Please use short-term emission rates for all pollutants with short-term averaging times.

Response: For modeling purposes, the maximum short-term CO emission rates were used in the modeling analyses to assess the Project's 1-hour and 8-hour average CO impacts. The CO impacts were predicted for the range of operating loads and temperatures using the maximum hourly CO emissions for distillate light oil combustion presented in Table 2-5 for simple cycle operation and Table 2-6 for combined cycle operation. Please refer to the modeling files submitted with the application which identify the combustion turbines for the simple cycle operation and combined cycle operation with the letters beginning "OS" and "OC", respectively.

It should be noted that the maximum annual CO emissions of 154.5 TPY for the simple cycle operation are presented in Table 2-1 as part of the PSD applicability analysis performed for the Project.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to department requests for additional information of an engineering nature. Therefore, please find attached a signed and sealed P.E. certification accompanying this submittal.

If you should have any questions regarding this letter and attachments, please don't hesitate to contact Scott Osbourn, P.E. at (813) 287-1717 or me at (727) 820-5962.

Sincerely,

Ann Quillian

Ann Quillian, P.E.
Senior Environmental Specialist

Enclosures

cc: Scott Osbourn, P.E., Golder Associates Inc.
Jim Little, EPA Region IV
John Bunyak, NPS
Mara Nasca, DEP, SW District
Gary Robbins, PCDEM

xc: Rufus Jackson, PEF
Jamie Hunter, PEF
Andy MacGregor, PEF

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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 St., Suite 114**
   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] 9/26/06

Signature Date

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

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

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.

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:

One – 300 HP diesel fuel-fired internal combustion engine (emergency fire pump).

3. Emissions Unit Identification Number:

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
C	**12/01/06**		**49**	☐ Yes ☒ No

9. Package Unit:
Manufacturer: **Clarke/John Deere** Model Number: **JW6H-UF58**

10. Generator Nameplate Rating: MW

11. Emissions Unit Comment:

The addition of a diesel-fired emergency fire pump reflects a change in the project design that occurred after the initial air application was submitted. This 300 HP Clarke/John Deere engine will meet all requirements of the new NSPS (*Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*), recently promulgated on July 11, 2006 in *Federal Register, Volume 71, Number 132*.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Good Combustion Practice – Diesel fuel fired.**	
2. Control Device or Method Code(s): **NA**	

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: **2.1** 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 **500** hours/year

6. Operating Capacity/Schedule Comment:

Maximum heat input based on fuel heating value of 150,000 Btu/gal.

The emergency generator will not be subject 40 CFR 63 Subpart ZZZZ, the Reciprocating Internal Combustion Engine (RICE) MACT Rule since it will be used for emergency purposes and qualify for the exemption, as described below:

Emergency Generator - Any stationary RICE that operates in an emergency situation. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility is interrupted, *or stationary RICE used to pump water in case of fire or flood*, etc. Emergency stationary RICE may be operated for the purpose of maintenance checks and readiness testing provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of the emergency stationary RICE in emergency situations and for routine testing and maintenance. Emergency stationary RICE may also operate an additional 50 hours per year in non-emergency situations.

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: **Adjacent to PB 4**	2. Emission Point Type Code:	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:		
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: **0.5** feet
8. Exit Temperature: **866** °F	9. Actual Volumetric Flow Rate: **1,642** acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates... Zone: East (km): North (km):	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) Longitude (DD/MM/SS)	
15. Emission Point Comment:		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type): **Diesel fuel combustion**		
2. Source Classification Code (SCC):	3. SCC Units: **1000 gallons**	
4. Maximum Hourly Rate: **0.014**	5. Maximum Annual Rate: **7.0**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment: **Maximum annual rate based on estimated 500 hr / yr operation.**		

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
CO			EL
PM/PM10			EL
NMHC+NOx			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: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.67** lb/hour **0.17** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **1.01 g/hp-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **5**
8. Calculation of Emissions: **Annual emissions based on 500 hr/yr.**	
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: **1.01 g/hp-hr**	4. Equivalent Allowable Emissions: **0.67** lb/hour **0.17** tons/year
5. Method of Compliance: **Diesel fuel combustion**	
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):	

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: **NMHC+NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3.7** lb/hour **0.93** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5.52 g/HP-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **5**
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: **5.52 g/HP-hr**	4. Equivalent Allowable Emissions: **3.7** lb/hour **0.93** tons/year
5. Method of Compliance: **Diesel fuel combustion**	
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):	

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.)

<u>**Potential/Estimated Fugitive Emissions**</u>

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: **0.15** lb/hour **0.04** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.23 g/HP-hr** Reference: **John Deere, 2006**	7. Emissions Method Code: **5**
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: **0.23 g/HP-hr**	4. Equivalent Allowable Emissions: **0.15** lb/hour **0.04** tons/year
5. Method of Compliance: **Diesel fuel combustion**	
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):	

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 _____ 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:	

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 _____ 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: ☒ Previously Submitted, Date **July 31, 2006**

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: ____ ☒ Previously Submitted, Date **July 31, 2006**

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: **Attach 5** ☐ 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: **Attach 5** ☐ 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

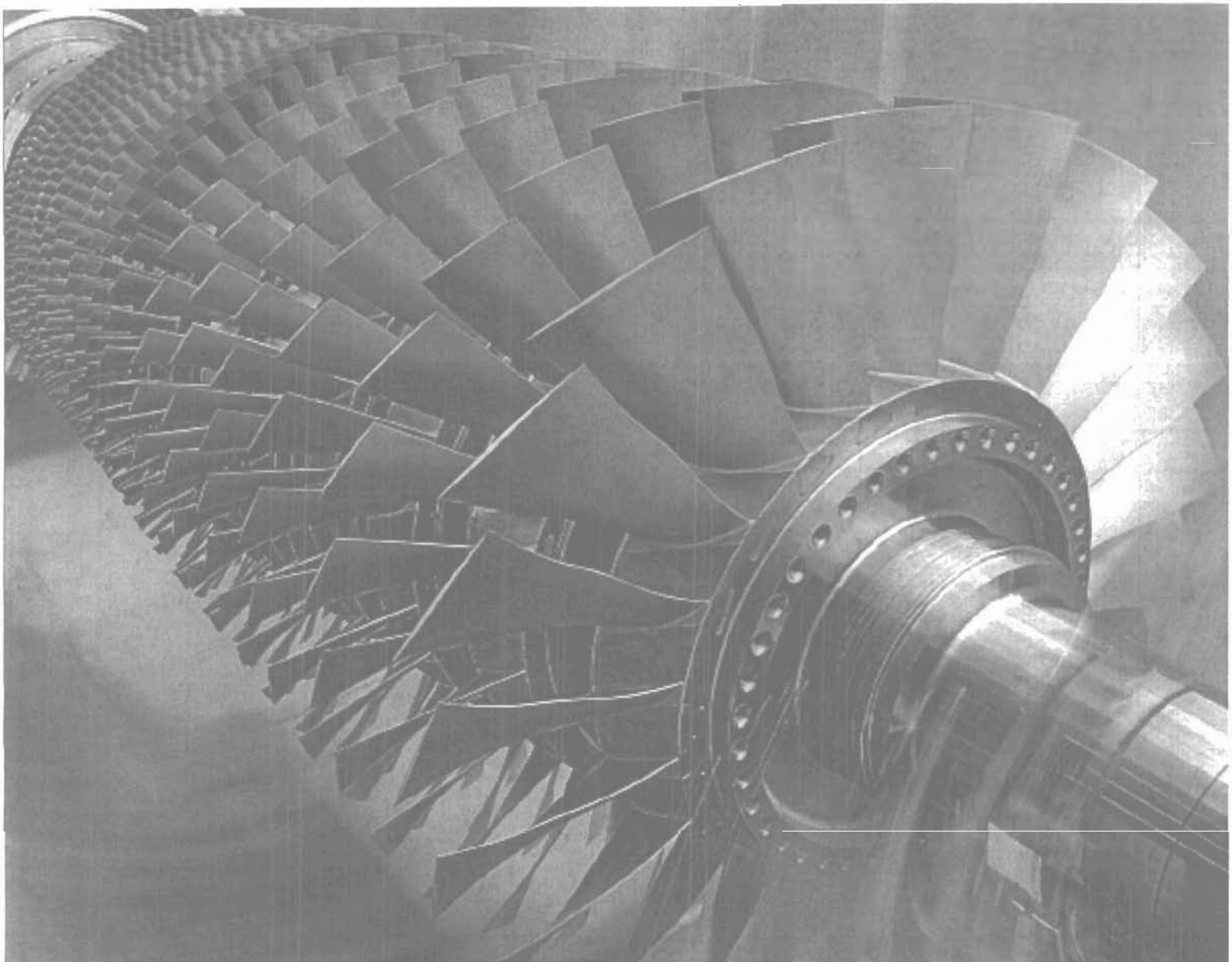
Additional Requirements for Title V Air Operation Permit Applications

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 1

SIEMENS EQUIPMENT BROCHURE



Gas Turbines

Reliability with Flexibility
Siemens Gas Turbine

SGT6-5000F

Power Generation

SIEMENS

Revolutionary performance through evolutionary design

At the forefront of the gas turbine industry, the uncompromising Siemens Gas Turbines (SGT™) continue to set reliability and continuous operation records. Packaged with the generator and other auxiliary modules the SGT6-5000F* is the muscle within the stand-alone power generation package (SGT-PAC) known as the SGT6-PAC 5000F**. The 60 Hertz SGT6-5000F gas turbine has more than 2.5 million hours of fleet operation and net combined cycle efficiencies of 57%. These achievements are the result of successfully implementing increments of performance improvements into a proven technology platform.

The SGT6-PAC 5000F power generation system provides economical power for peaking duty, operational flexibility and load following capabilities for intermediate duty, while maintaining high efficiencies for continuous service.

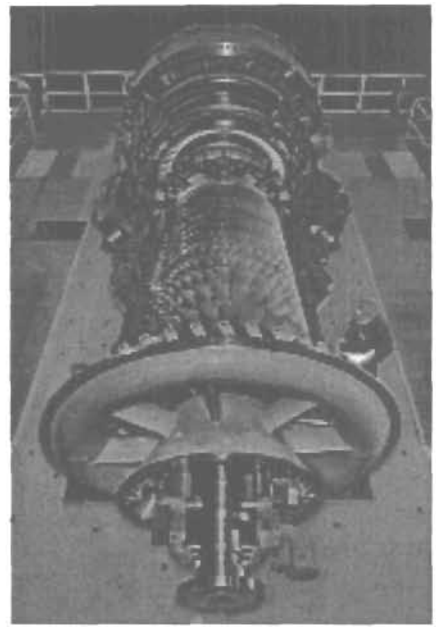
Key system benefits include:

- Most powerful 60 Hertz F-class engine – capable of over 230 MW
- High simple and combined cycle efficiencies
- Single digit ppm NOx and CO capability
- Cyclic capability including daily start/stop – 10 minute start-up capability
- Hot re-start capability – without time delay
- Foremost maintainability – easily removable blading and combustion components
- High reliability – 99% average
- Advanced service and maintenance technologies for increased availability

The SGT6-5000F gas turbine is ideally suited for simple cycle and heat recovery applications including IGCC, cogeneration, combined cycle and repowering. Flexible fuel capabilities include natural gas, LNG, distillate oil and other fuels, such as low- or medium-BTU gas.

The SGT6-PAC 5000F plant is your 60 Hertz power solution. And, because of its evolutionary design philosophy, the Siemens SGT6-PAC 5000F plant will continue to meet your requirements for years to come.

* *SGT6-5000F gas turbine engine was formerly called the W501F*
** *SGT6-PAC 5000F power plant was formerly called the W501F ECONOPAC*



Gas turbine

As the heart of the SGT6-PAC 5000F plant, the SGT6-5000F gas turbine consists of three basic elements: axial-flow compressor, combustion system and turbine section. Incorporated into the design are such proven features as horizontally split casings, two-bearing rotor support, external rotor air cooler, and axial-flow exhaust.

The compressor is a 16-stage axial flow design, which achieves a 17 to 1 pressure ratio. The compressor is equipped with one stage of variable inlet guide vanes to improve the low speed surge characteristics and part load performance in combined cycle applications.
The blade path design is based on an advanced 3-D flow field analysis computer model. Each stage of stationary airfoils consists of two 180° diaphragms for easy removal. One row of exit guide vanes is used to direct the flow leaving the compressor. Stationary airfoils and shrouds utilize corrosion and heat-resisting stainless steel throughout. All compressor rotating and stationary airfoils are coated to improve aerodynamic performance and corrosion protection. The compressor rotor is comprised of a number of elements that are keyed, spigotted and bolted together by 12 through bolts.

The combustion system consists of 16 can-annular combustors. Each combustor has an air-cooled transition piece, which directs the combustion gases to the turbine blade path.

The turbine section is comprised of four stages each containing a stationary and rotating row of blading. The turbine rotor, which contains the rotating blades is constructed of four interlocking discs using Curvic® couplings that are held together using 12 through bolts.

The Curvic® coupling, machined into the face of each disc, mates with the adjoining disc to provide precise alignment and exceptional torque carrying capabilities. The Curvic® coupling also maintains contact during the differential thermal expansions that result from normal gas turbine operation. Design features include advanced materials, coatings, and cooling schemes that are implemented throughout the turbine section to yield high turbine efficiencies and maintain long turbine component life.

Rotor air cooler

A comprehensive cooling system is provided to supply cooling air to the high temperature areas of the turbine section. Rotor cooling air is extracted from the combustor shell. The air is externally cooled before being returned to the rotor to be used for seal air supply and for cooling of the turbine discs and the first, second, and third stage turbine rotor blades. This provides a blanket of protection from hot blade path gases and allows the use of more ductile materials throughout the turbine rotor.

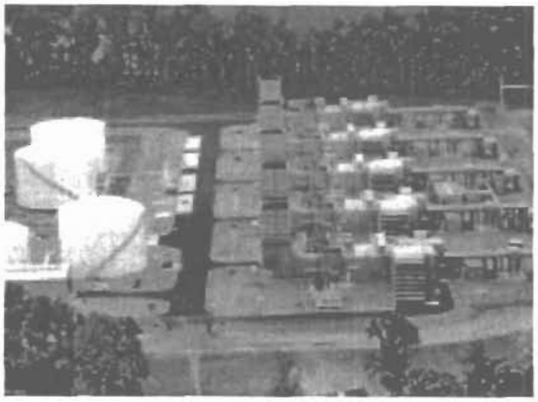
In combined cycle applications, the "waste" energy removed from the cooling air is used to produce low pressure steam which is introduced into the steam circuit to increase steam turbine output and cycle efficiency. Alternatively, this energy can be reclaimed for fuel heating or boiler feed water heating.

Inlet air system

A side- or top-mounted inlet duct directs airflow into the compressor inlet manifold. The manifold is designed to provide an efficient flow pattern of air into the axial-flow compressor. A parallel-baffle silencing configuration is located in the inlet system for sound attenuation.
Air filtration is provided by a two-stage pad filter as the standard arrangement. Other filter systems are also available.

Generator

The SGT6-5000F engine is coupled to an open air-cooled (OAC) generator which is equipped with cooling air filtration, silencers, inlet and exhaust ducting, brushless excitation, acoustical enclosure and necessary instrumentation. Main three-phase terminals are located on top of the acoustical enclosure at the excitation end of the generator for isophase interface. Internal cooling is provided via shaft-mounted axial blowers which direct filtered ambient air through the generator's major internal components. The brushless exciter and voltage regulator system supplies generator field excitation and controls the AC generator terminal voltage. The brushless exciter has a shaft-mounted rotating armature and diode wheel. The voltage regulator supplies the stationary DC field to the brushless exciter, either under automatic or manual control. A static excitation system is an option. Totally enclosed water-to-air-cooled (TEWAC) or hydrogen-cooled generators are also options.



SGT6-5000F gas turbine technology in typical applications for simple cycle, combined cycle and cogeneration

Exhaust system

After expanding through the turbine, the gases are ducted into the plenum of the exhaust stack.

For heat recovery applications, the exhaust stack is deleted and the gases are directed to the heat recovery steam generator.

Electrical and control package

The electrical and control package contains equipment necessary for sequencing, control, and monitoring of the turbine and generator. This includes the Siemens Power Plant Automation (SPPA™) system known as the SPPA-3000* microprocessor-based distributed control system, motor control centers, generator protective relay panel, voltage regulator, fire protection control system, batteries and battery charger. The batteries are in an isolated section of the package and are readily accessible for maintenance.

Lubricating oil package

The lubricating oil package houses the common lube oil system for the gas turbine and generator.

Gas fuel system

The main components of the gas fuel system are located within the gas turbine enclosure.

A pressure switch and gauge panel is provided for local monitoring of the gas system.

* *SPPA-3000 was formerly known as the TXP.*

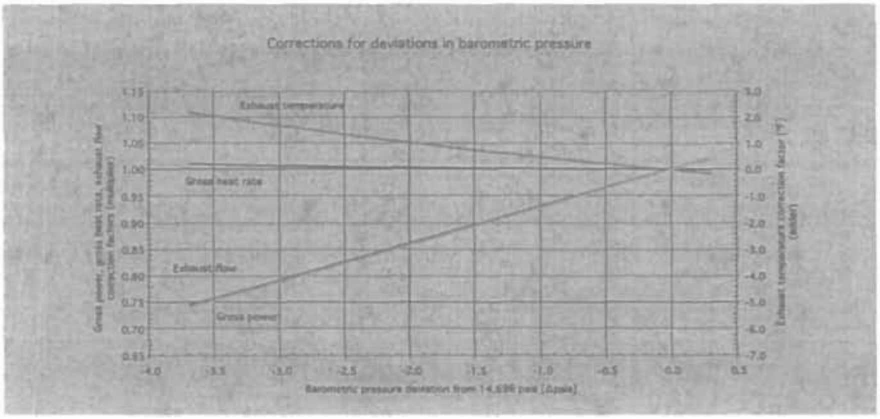
Net performance for the SGT6-PAC 5000F

Power plant conditions: Natural gas or liquid fuel meeting Siemens Power Generation's fuel specifications, sea level, 60% relative humidity, 59°F (15°C) inlet air temperature, 3.4 in. water (87 mm water) inlet loss, 5 in. water (127 mm water) exhaust loss, air-cooled generator and .90 power factor (pf).

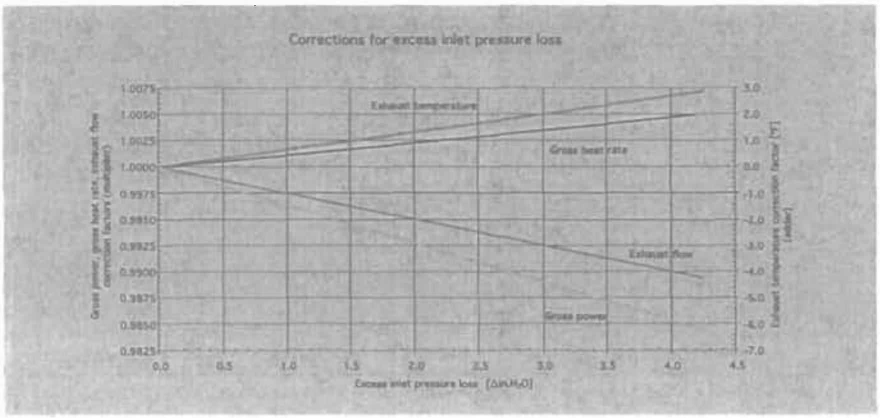
Combustor type	DLN dry	Conventional water injection	Conventional steam injection	DLN* steam augmentation
Fuel	**Natural gas**	**Natural gas**	**Natural gas**	**Natural gas**
Net power output (kW)	194,500	206,200	214,000	213,190
Net heat rate (Btu/kWh) (LHV)	9,087	9,471	8,763	8,870
Net heat rate (kJ/kWh) (LHV)	9,587	9,992	9,245	9,350
Exhaust temperature (°F/°C)	1,075/579	1,048/564	1,068/576	1,078/581
Exhaust flow (lb/hr)	3,934,800	4,050,000	4,063,000	4,060,300
Exhaust flow (kg/hr)	1,785,600	1,836,000	1,846,800	1,841,760
Fuel flow (lb/hr)	82,164	90,787	87,178	93,990
Fuel flow (kg/hr)	37,269	41,181	39,544	42,640
Fuel	**Liquid**	**Liquid**	**Liquid**	**Liquid****
Net power output (kW)	184,800	191,500	204,200	-
Net heat rate (Btu/kWh) (LHV)	9,425	9,647	8,855	-
Net heat rate (kJ/kWh) (LHV)	9,944	10,178	9,343	-
Exhaust temperature (°F/°C)	1,036/558	1,021/549	1,042/561	-
Exhaust flow (lb/hr)	3,981,600	4,050,000	4,093,200	-
Exhaust flow (kg/hr)	1,807,200	1,836,000	1,857,600	-
Fuel flow (lb/hr)	94,148	99,859	97,740	-
Fuel flow (kg/hr)	42,706	45,296	44,335	-

* Steam injected through the combuster section casing into the compressor discharge air to increase output

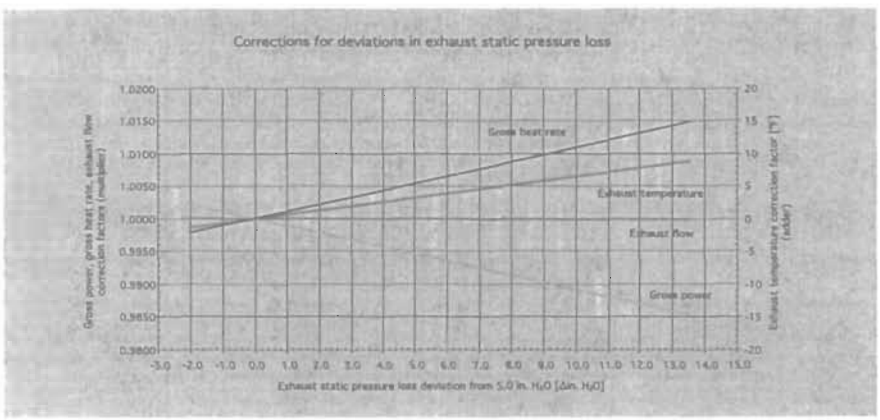
** Steam augmentation with liquid fuel available on a case-by-case basis



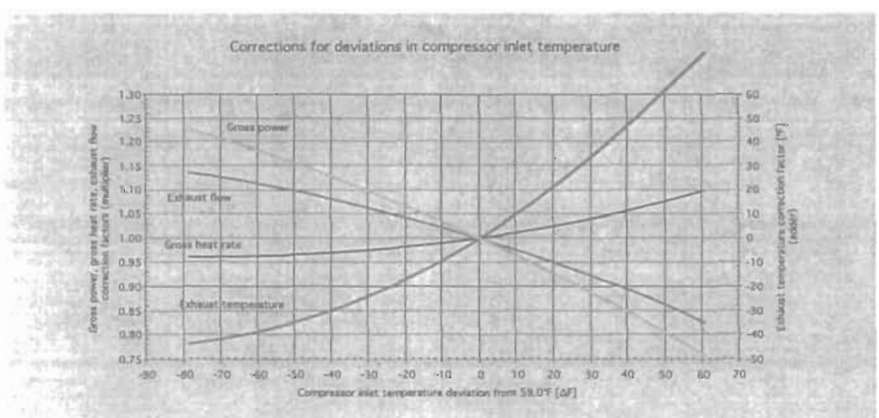
Corrections for deviations in barometric pressure
Exhaust temperature
Gross heat rate
Exhaust flow
Gross power
Barometric pressure deviation from 14.696 psia [Δpsia]
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)



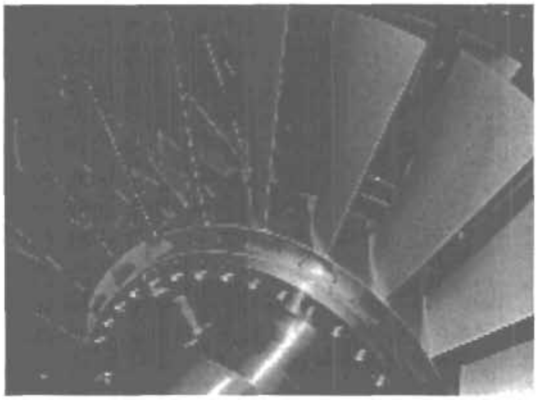
Corrections for excess inlet pressure loss
Exhaust temperature
Gross heat rate
Exhaust flow
Gross power
Excess inlet pressure loss [Δin.H₂O]
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)



Corrections for deviations in exhaust static pressure loss
Gross heat rate
Exhaust temperature
Exhaust flow
Gross power
Exhaust static pressure loss deviation from 5.0 in. H₂O [Δin. H₂O]
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)



Corrections for deviations in compressor inlet temperature
Gross power
Exhaust flow
Gross heat rate
Exhaust temperature
Compressor inlet temperature deviation from 59.0°F [ΔF]
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)



Compressor wash package

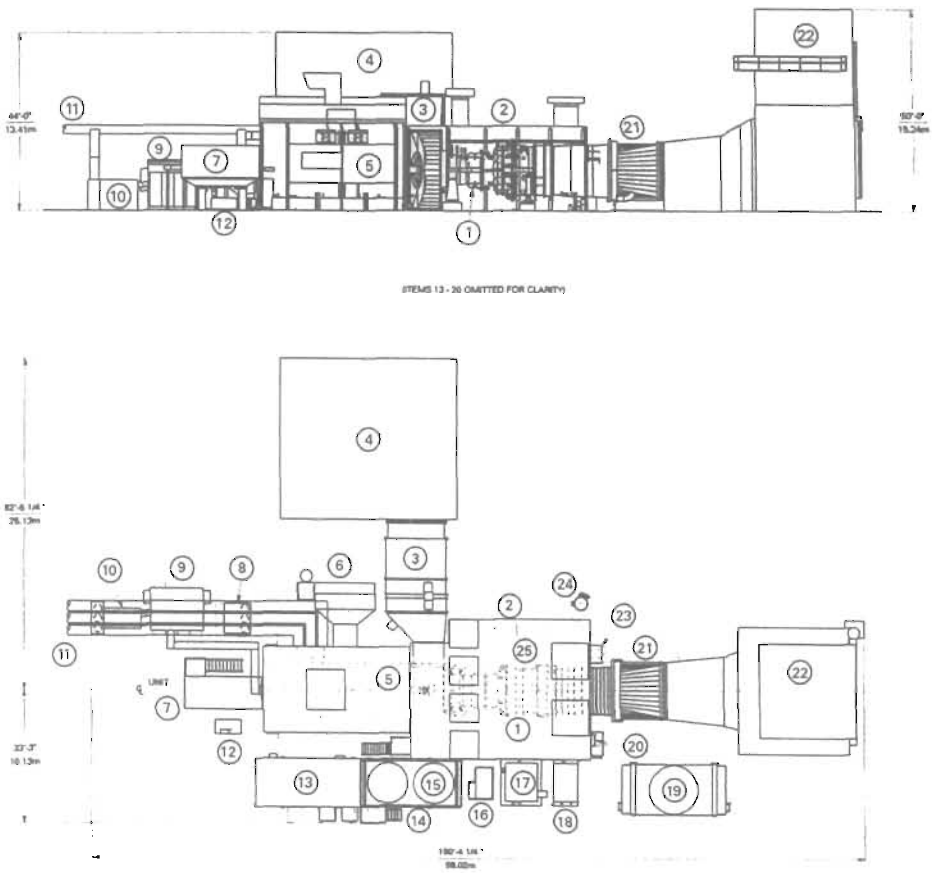
The compressor wash package is provided for both on-line and off-line compressor cleaning. This package accommodates the pump, eductor for detergent injection, piping, valving, orifices and detergent storage tank.

Cooler assemblies

An oil-to-air lube oil cooler is located above the lubricating oil package. An air-to-air cooler for turbine rotor cooling is placed adjacent to the exhaust stack. Other cooler options are available for combined cycle applications.

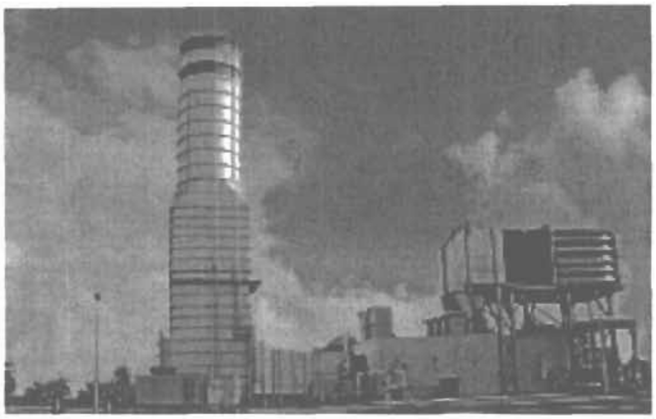
Pipe rack assemblies

Piping for the SGT6-PAC 5000F power plant is designed and manufactured to minimize field work. Each of the major plant modules is completely factory pre-piped, requiring only a few field connections. This is enhanced by the supply of a factory-assembled pipe rack. This turbine pipe rack, located adjacent to the gas turbine in the turbine enclosure, contains piping and valves for the cooling air and lube oil supply and return.



SGT6-PAC 5000F Typical General Arrangement

1. *Gas turbine*
2. *Gas turbine enclosure*
3. *Air inlet duct and silencer*
4. *Air inlet filter*
5. *Generator (open air-cooled)*
6. *Generator air inlet filter*
7. *Starting package*
8. *VT & surge cubicle*
9. *Excitation skid*
10. *Excitation transformer*
11. *Isophase bus duct*
12. *Compressor wash skid*
13. *Electrical package*
14. *Lubricating packaging*
15. *Lube oil coolers (fin-fan type)*
16. *Hydraulic supply skid (air cooler)*
17. *Fuel oil pump skid (optional)*
18. *Water injection pump skid (optional)*
19. *Rotor air cooler (fin-fan type)*
20. *Dry chemical cabinet*
21. *Exhaust transition*
22. *Exhaust stack*
23. *FM2000 fire cabinet*
24. *Fuel gas main filter/separator*
25. *Fuel oil water injection skid (optional)*



SGT6-PAC 5000F Power plant in typical arrangement

Technical data

Gas turbine

Rotor speed	3600 rpm
Compressor	
Number of stages	16
Pressure ratio	17:1
Combustors	
Number	16
Type	Can-annular Dry low NO_x
Turbine	
Number of stages	4

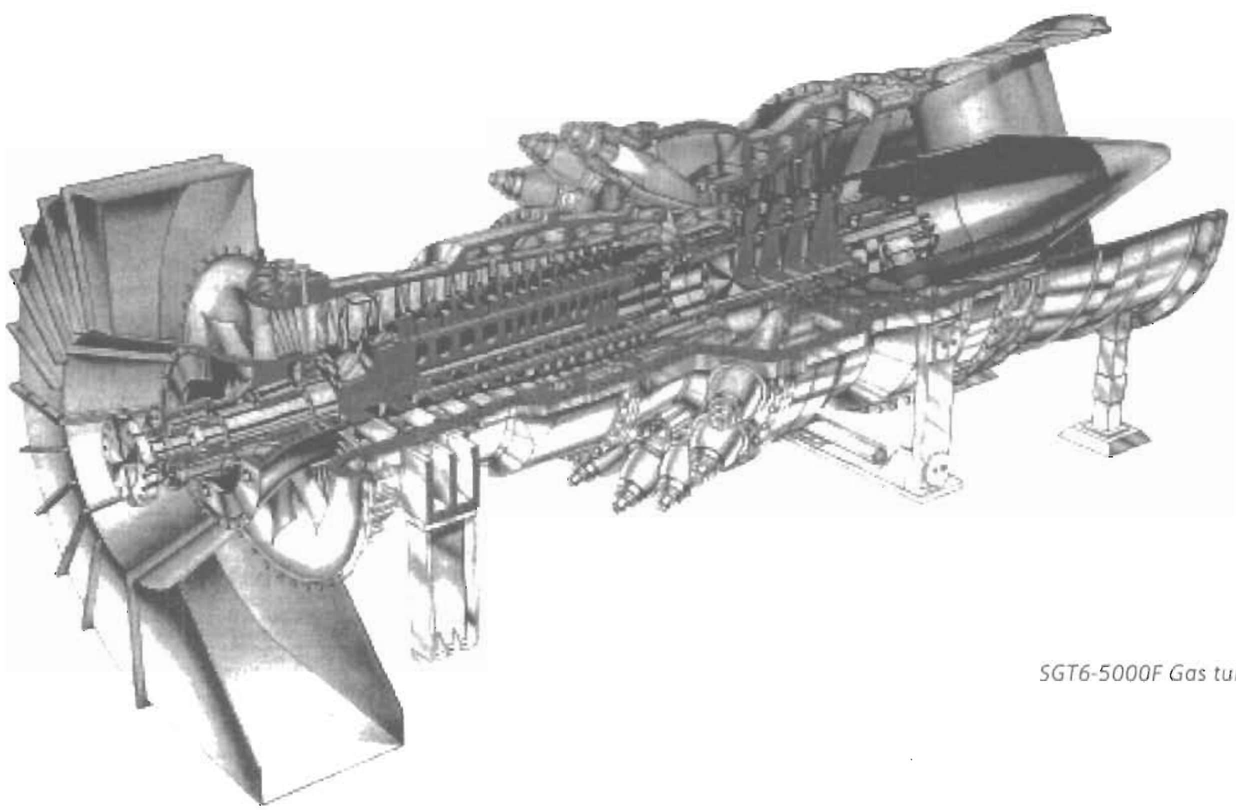
Generator

Type	— Standard	Open air-cooled
	— Option	Totally enclosed water-to-air cooled
	— Option	Hydrogen-cooled
Frequency		60 Hz
Voltage		15 kV
Insulation		Class F

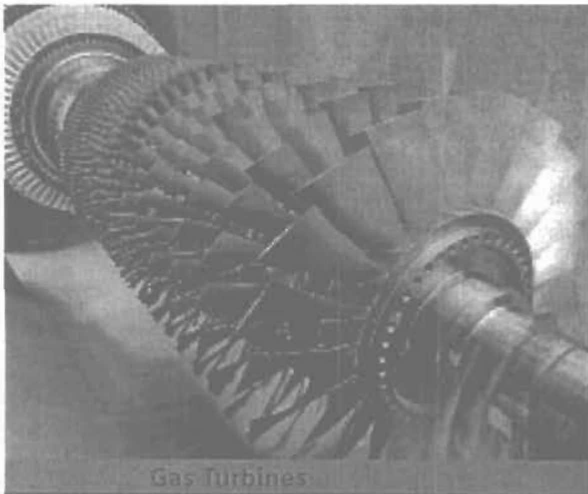
Major weights

Generator/collector	530,000 lb	(240,400 kg)
Gas turbine	462,000 lb	(209,560 kg)
Lubricating package	60,000 lb	(27,200 kg)
Electrical package	33,000 lb	(14,970 kg)
Starting package	36,500 lb	(16,560 kg)
Turbine rotor/lifting beam*	110,000 lb	(49,900 kg)

* *Heaviest piece to be lifted after installation*



SGT6-5000F Gas turbine



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www.siemens.com/powergeneration

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ATTACHMENT 2

FORMALDEHYDE TEST DATA

Formaldehyde (HCHO) Test Data Summary - Natural Gas Operation

Frame	Load	HCHO (ppmvd @ 15% O_2)	SCR Present
W501G	10	27.765	No
	30	25.518	
	50	9.833	
	70	4.761	
W501FD2	70	0.002	No
	Base	< 0.0018	
W501FD	50	0.042	No
		0.286	
	75	0.003	
		0.004	
	Base	~0.0037	
		<0.0039	
W501FC	26	47.900	Yes
		49.700	
	Base	<0.0054	
		<0.0054	
		<0.0067	
V94.3A	100	0.060	No
		0.052	
	70	0.052	
		0.075	
	55	0.045	
		0.052	
	40	0.254	
		0.269	
	20	3.433	
		3.881	
	0	5.374	
		5.001	
V84.3A	75	0.057	No
		0.054	
		0.068	
		0.018	
		0.006	
		0.009	
	Base	0.054	
		0.191	
		0.060	
		0.003	
		0.012	
		0.005	
	Base+PAG/WI	0.065	
		0.049	
		0.059	
		0.040	
		0.009	
V84.3A2	10	72.261	No
	30	7.063	
	50	0.834	
	75	0.269	

Initial Compliance Test Report
for
Natural Gas Fueled Stack Emissions

on
Power Block 1

consisting of
Units 1A and 1B, two Westinghouse 501F Combined Cycle Combustion Turbines

at the
Hines Energy Complex

in
Polk County, Florida

Prepared for
Florida Power Corporation

February 1999

Cubix Job No. 491L

Prepared by

Cubix Corporation
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INTRODUCTION

Emission testing was conducted on Power Block 1, which consists of two combined cycle combustion turbines manufactured by Siemens Westinghouse Power Corporation. These units, used to generate power, were recently installed at the Hines Energy Complex located near Fort Meade in Polk County, Florida. Florida Power Corporation (FPC) owns and operates this facility. This report documents the testing of each combustion turbine while fueled with natural gas. A separate report will be provided for the testing of the units while fueled with No. 2 fuel oil. The testing was conducted by Cubix Corporation, Southeast Regional Office on December 29 and 31, 1998, and on January 1 to 2, 1999.

The purpose of this testing was to determine the status of initial compliance for combustion turbine emissions with the permit limits set forth by the Florida Department of Environmental Protection (FDEP), Permit Numbers PSD-FL-195A and PA-92-33. Additionally, the emissions were measured to determine compliance with the Environmental Protection Agency (EPA) Code of Federal Regulations, Title 40, Part 60, (40 CFR 60) Subpart GG "Standards of Performance for Stationary Gas Turbines". The tests followed the procedures set forth in 40 CFR 60, Appendix A, Methods 1, 2, 3a, 4, 5, 9, 10, 19, 20, 25a, and 26a (modified).

Each turbine's exhaust was analyzed for oxides of nitrogen (NO_X), carbon monoxide (CO), total hydrocarbon compounds (THC), oxygen (O_2), and carbon dioxide (CO_2) using continuous instrumental monitors. Particulate matter (PM) and ammonia (NH_3) samples were collected iso-kinetically using a combined hot/cold manual sampling train. Ammonia samples were analyzed on-site using the Nessler procedure and also by Triangle Laboratories, Inc. of Durham, North Carolina using ion chromatographic procedures. Visible emissions (VE) were determined by a certified observer. Analysis of the natural gas fuel was provided by Florida Gas Transmission Company's laboratory in Perry, Florida. Table 1 provides background data pertinent to these tests.

This test report has been reviewed and approved for submittal to the FDEP by the following representatives:

Leonard [signature]
Cubix Corporation

[signature]
Florida Power Corporation

TABLE 1
BACKGROUND DATA

Owner/Operator:	**Florida Power Corporation** One Power Plaza, 263 13th Avenue South, BB1A St. Petersburg, Florida 33701-5511 (727) 826-4258 TEL (727) 826-4216 FAX Attn: Scott Osbourn, Sr. Environmental Engineer
Testing Organization:	**Cubix Corporation, SE Regional Office** 4536 NW 20th Drive Gainesville, Florida 32605 (352) 378-0332 TEL (352) 378-0354 FAX Attn: Leonard Brenner, Project Manager
Test Participants:	**Florida Power Corporation** Scott Osbourn J. William Agee **Siemans Westinghouse Power Corporation** Ramesh Kagolanu **FDEP** Martin Costello Robert Soich Henry Gotsch **Cubix Corporation** Leonard Brenner Jose Antonio "Tony" Ruiz Juan Ramirez Roger Paul Osier

Test Dates:	December 29 and 31, 1998 January 1 and 2, 1999
Facility Location:	Hines Energy Complex 7700 County Road 555 Bartow, Florida 33830 Latitude: 27°47'19" North Longitude: 81°52'10" West
Process Description:	Two combined cycle combustion turbines (CTs) are used to generate electrical power. Each unit, a Westinghouse Model 501F, consists of a single shaft gas combustion turbine directly connected to a 60 Hz power generator. Each turbine is equipped with an unfired heat recovery steam generator (HRSG) to drive steam turbines for additional power generation. The facility is designed to provide either No. 2 fuel oil or natural gas fuel to each combustion turbine.
Regulatory Application:	Florida Department of Environmental Protection (FDEP) Permit Nos. PSD-FL-195A and PA-92-33 and EPA New Source Performance Standards (NSPS) 40 CFR 60, Subpart GG.
Emission Sampling Points:	Each exhaust stack is a circular stack 130' tall with a diameter of 216". Four 6" sample ports are located 90° from each other at 107' above grade. Access to the sample ports are provided with a permanently mounted steel grate service platform equipped with a caged safety ladder.
Test Methods:	EPA Method 1 for oxygen (O_2) and particulate matter (PM) traverse point locations. EPA Method 2 for stack gas differential pressure measurements during PM sampling. EPA Method 3a for carbon dioxide (CO_2) concentrations. EPA Method 4 for stack gas moisture content.

Test Methods (Cont.'):

EPA Method 5 for particulate matter (PM) concentrations.

EPA Method 9 for visible emissions (VE) measurements determined as opacity from a certified observer.

EPA Method 10 for carbon monoxide (CO) concentrations.

EPA Method 19 for the calculation of volumetric flow and pollutant mass emission rates.

EPA Method 20 for oxides of nitrogen (NO_X) and oxygen (O_2) concentrations.

EPA Method 25a for total hydrocarbon compound (THC) concentrations.

EPA Method 26a (modified) for ammonia (NH_3) sample collection.

The Nessler Procedure for on-site analysis of NH_3 concentrations.

EPA Draft Method 206 for ion chromatographic analysis for NH_3 concentrations by Triangle Laboratories, Inc.

Total sulfur analysis of the natural gas fuel by the Florida Gas Transmission Company Perry Laboratory.

SUMMARY OF RESULTS

Florida Power Corporation (FPC) owns and operates the Hines Energy Complex in Polk County, Florida. At this facility two Westinghouse combined cycle combustion turbines, each equipped with an unfired heat recovery steam generator (HRSG), are used to generate electrical power. The combustion turbines are designated as Unit 1A and Unit 1B by FPC. Stack emissions from these units, while fueled with natural gas, are the subject of this report. Emissions from these units, while fueled with fuel oil, will be reported separately.

The first step in the test matrix for each unit consisted of conducting an initial sampling traverse of the combustion turbine/heat recovery steam generator (CT/HRSG) exhaust stack. The purpose of this sampling traverse was to check for changes in O_2 concentration (stratification) within the exhaust stack. Each turbine was set to the lowest load representative of normal operation, approximately 90 megawatts (MW), while operating under dry, low NO_X combustion and with Selective Catalytic Reduction (SCR) operating. O_2 concentrations were measured at 48 traverse points within the CT/HRSG stack to determine the eight points of lowest O_2 concentration. This initial traverse was conducted on each CT/HRSG stack. No significant stratification was found in either exhaust stack; therefore, all subsequent tests were conducted at the eight most convenient traverse points on each unit.

Following the O_2-traverse, Cubix conducted three test runs at each of four load conditions across the operational range of the combustion turbine (~90 MW, ~110 MW, ~135 MW, and full load at ~165 MW). Each reduced load test run was 18 minutes and 40 seconds in duration (8 sample points, 140 seconds per point). The first reduced load test was conducted concurrently with the initial O_2-traverse. Full load is defined as 90 to 100% of the maximum permitted capacity, expressed as heat input, determined from the Westinghouse performance curve of heat input versus turbine inlet temperature for the unit. NO_X, O_2, and CO_2 were continuously monitored at all load conditions. Additional full load measurements included CO and THC using continuous instrumental monitors and iso-kinetic sampling for collection of PM and NH_3 samples. The full load test runs were 1 hour in duration for all constituents except PM and NH_3 which were performed for 2 to 3 hours to collect an appreciable amount of sample. A one-hour VE test was conducted simultaneously with one of the full load test runs. This test matrix was performed on both CT units.

Table 2, the executive summary, signifies the performance for each unit during the full load testing. These performance results are an average of the three full load test runs for each unit. These emissions are compared to the permit limits set forth in FDEP Permit Nos. PSD-FL-195A and PA-92-33.

TABLE 2
Executive Summary

Parameter	Unit 1A Westinghouse 501F Turbine	Unit 1B Westinghouse 501F Turbine	NSPS/FDEP Permit Limits
Percent Load (of capacity as heat input)	100.0%	99.8%	90 to 100%
NO_x (lbs/hr at 67°F inlet temperature)	63.5	-	71.77
NO_x (lbs/hr at 61°F inlet temperature)	-	67.8	72.69
VOC (lbs/hr, from THC measurements)	0.33	0.73	10.4
CO (lbs/hr)	2.11	2.56	77
PM/PM_{10} (lbs/hr)	2.54	2.97	15.6
SO_2 (lbs/hr)	1.63	1.65	4.7
Visible Emissions (% opacity)	0%	0%	10%
NH_3 (ppmv, dry basis by Nessler analysis)	3.84	6.15	10
NH_3 (ppmv, dry basis by Ion Chromatography)	3.57	4.19	10

Tables 3 and 4 represent the Unit 1A test results for full load and reduced load testing, respectively. These tabular summaries contain all pertinent operational parameters, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of parts per million by volume (ppmv) on a dry basis, ppmv corrected to 15% excess O_2, and ppmv corrected to 15% excess O_2 and ISO conditions. The EPA defines ISO conditions as ambient atmospheric conditions of 59 degrees Fahrenheit (°F) temperature, 101.3 kilopascals (kPa) pressure, and 60% relative humidity. CO and NH_3 concentrations were determined on ppmv, dry basis. Volatile organic compound (VOC) concentrations were determined from THC measurements and were determined on a ppmv, wet basis as methane. Concentrations of PM were determined in units of grams per dry standard cubic feet (grams PM/DSCF). Mass emission rates for NO_X, CO, VOC, PM, NH_3, and SO_2 are reported in terms of pounds per hour (lbs/hr). As stated in the test matrix above, only NO_X concentrations and emissions were applicable for the reduced load tests.

Tables 5 and 6 represent the Unit 1B test results for full load and reduced load testing, respectively. These tabular summaries contain all pertinent operational parameters, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of ppmv on a dry basis, ppmv at 15% excess O_2, and ppmv at 15% excess O_2 and ISO conditions. CO and NH_3 concentrations were determined on ppmv, dry basis. VOC concentrations were determined from THC measurements and were determined on a ppmv, wet basis as methane. Concentrations of PM were determined in units of grams PM/DSCF. Mass emission rates for NO_X, CO, VOC, PM, NH_3, and SO_2 are reported in terms of lbs/hr.

Volumetric flow and mass emission rates were determined by stoichiometric calculation (EPA Method 19) based on measurements of diluent gas (O_2 or CO_2) concentrations, "F-factors" determined from fuel composition, and unit fuel flow rates. Examples of iso-kinetic calculations, emission rate calculations, and other calculations necessary for the presentation of the results of this section are contained in Appendix B.

The fuel sulfur content analyses, concentration in ppmv, is contained in Appendix C of this report. The fuel was analyzed on-line for total fuel sulfur content by Florida Gas Transmission's Perry Laboratory. The SO_2 emission rates, reported in lbs/hr, were calculated from the results of these analyses and the measured fuel flow rates recorded during the tests.

Visible emission observations of each CT/HRSG exhaust stack per EPA Method 9 were performed by an observer certified by Eastern Technical Associates of Raleigh, North Carolina. A one-hour visible emissions test run was conducted on each unit. VE were an average of 0% opacity in the highest six-minute average for each test and no VE greater than 0% opacity was observed during the tests.

Appendix A contains all field data sheets used during these tests as well as the particulate matter analysis worksheets and the Nessler procedure ammonia analysis worksheets. Appendix B contains examples of all calculations necessary for the reduction of the data presented in this report. Appendix C contains the fuel analysis and Cubix's fuel calculation worksheet. Quality Assurance Activities are documented in Appendix D. Certificates of calibrations are contained in Appendix E of this report. Copies of the reference method strip chart records obtained during these tests are available in Appendix F of this report. Appendix G contains the "Visible Emissions Observation Forms" and the observer certifications. Appendix H contains the operational data provided by FPC during the test runs. Ion chromatography results from the ammonia analysis are presented in Appendix I. The FDEP facility permits and FDEP correspondence records are presented in Appendix J for reference purposes.

TABLE 3: Summary of Results
Full Load Testing
Unit 1A

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, JAR, JFR
Source: Unit 1A, a Westinghouse 501F Power Turbine

Test Number	Gas-AC-2	Gas-AC-3	Gas-AC-4		FDEP Permit Limits
Date	1/1/99	1/1/99	1/1/99		
Start Time	9:05	13:21	14:58		
Stop Time	10:05	14:21	15:59		
Turbine/Compressor Operation				*Averages*	
Generator Output (MW, CT generated power only)	171.4	164.0	163.7	*166.4*	
Heat Input (MMBtu/hr, higher heating value, HHV)	1,744	1,720	1,706	*1,723*	
Turbine Capacity (Mfg.'s Curve, heat input vs. inlet temp)	1,760	1,704	1,704	*1,723*	
Percent Load (% of maximum heat input at inlet temp)	99.1%	100.9%	100.1%	*100.0%*	
Engine Compressor Discharge Pressure (psia)	218.6	211.9	211.9	*214.1*	
Turbine Air Inlet Temperature (°F)	58.4	71.0	71.0	*66.8*	
Compressor Discharge Temperature Sel. (°F)	219	766	766	*584*	
Mean Turbine Exhaust Temperature (°F)	1130	1144	1147	*1140*	
SCR Ammonia Injection Rate (lbs/hr)	193.2	197.5	193.6	*194.8*	
Pre-SCR Temperature (SCR inlet temperature, °F)	613	613	613	*613*	
Post-SCR Temperature (SCR outlet temperature, °F)	646	646	646	*646*	
Turbine Fuel Data (Natural Gas, FGT)					
Fuel Heating Value (Btu/lb, HHV)	23122	23122	23122	*23122*	
Fuel Specific Gravity	0.5982	0.5982	0.5982	*0.5982*	
Sulfur in Fuel (grains/100 SCF of fuel gas)	0.375	0.375	0.375	*0.375*	1
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	8646	8646	8646	*8646*	
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1034	1034	1034	*1034*	
Fuel Flow (KPPH, natural gas)	75.43	74.38	73.80	*74.54*	
Heat Input (MMBtu/hr, Higher Heat Value)	1744.1	1719.8	1706.4	*1723.4*	
Heat Input (MMBtu/hr, Lower Heat Value)	1569.7	1547.8	1535.8	*1551.1*	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.83	29.76	29.73	*29.77*	
Temperature (°F): Dry bulb	70.0	74.0	71.8	*71.9*	
(°F): Wet bulb	63.0	63.0	61.9	*62.6*	
Humidity (lbs moisture/lb of air)	0.0105	0.0096	0.0094	*0.0098*	
Measured Emissions					
NO_X (ppmv, dry basis)	11.99	12.14	12.14	*12.09*	
NO_X (ppmv, dry @ 15% O_2)	9.9	10.0	10.3	*10.1*	
NO_X (ppmv @ 15% O_2, ISO Day)	10.8	10.3	10.6	*10.6*	
CO (ppmv, dry basis)	0.62	0.63	0.73	*0.66*	
THC (ppmv, wet basis)	0.38	0.02	0.10	*0.17*	
PM (grams PM/DSCF exhaust gas)	2.80E-05	3.53E-05	1.53E-05	*2.62E-05*	
NH_3 (ppmv, dry basis from ion chromatography per FDEP)	2.42	2.93	5.37	*3.57*	10
NH_3 (ppmv, dry basis from on-site Nessler analysis)	2.60	3.09	5.82	*3.84*	10
Visible Emissions (% opacity)	0			0	10
H_2O (% volume, from Method 5 sample train)	8.48	8.24	8.35	8.36	
O_2 (% volume, dry basis)	13.76	13.77	13.94	*13.82*	
CO_2 (% volume, dry basis)	4.16	4.21	4.08	*4.15*	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.72	1.69	1.71	*1.71*	
Stack Volumetric Flow Rates					
via O_2 "F_d-factor" (SCFH, dry basis)	4.41E+07	4.36E+07	4.43E+07	*4.40E+07*	
via CO_2 "F_c-factor" (SCFH, dry basis)	4.34E+07	4.22E+07	4.32E+07	*4.29E+07*	
Calculated Emission Rates (via M-19 O_2 "F-factor")					
NO_X (lbs/hr)	63.2	63.2	64.2	*63.5*	71.77†
CO (lbs/hr)	1.99	2.00	2.35	*2.11*	77
THC (lbs/hr)	0.76	0.04	0.20	*0.33*	10.4
PM (lbs/hr)	2.73	3.39	1.49	*2.54*	15.6
SO_2 (lbs/hr, based on fuel flow and fuel sulfur)	1.64	1.62	1.61	*1.63*	4.7

† Permit Limit based upon actual average turbine air inlet temperature during testing

TABLE 4: Summary of Results
Reduced Load Testing
Unit 1A

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, JFR, RPO, JAR
Source: Unit 1A, a Westinghouse 501F Power Turbine

Test Number	Gas-AC-1	Gas-AC-11	Gas-AC-12	Gas-AC-8	Gas-AC-9	Gas-AC-10	Gas-AC-5	Gas-AC-6	Gas-AC-7
Date	12/31/98	1/2/99	1/2/99	1/1/99	1/2/99	1/2/99	1/1/99	1/1/99	1/1/99
Start Time	18:25	13:57	14:50	20:31	12:43	13:13	18:11	18:41	19:17
Stop Time	21:07	14:17	15:09	20:50	13:02	13:32	18:30	19:01	19:37
Turbine/Compressor Operation	Low Load, ~86 MW			Mid Load-1, ~108 MW			Mid Load-2, ~135 MW		
Generator Output	85.0	80.8	90.9	110.9	107.3	106.9	135.4	135.0	135.1
Heat Input (higher heating value, HHV)	1033.6	1035.9	1123.3	1216.9	1242.8	1242.8	1416.7	1404.9	1404.9
Turbine Capacity (Mfg.'s Curve, heat input vs. inlet temp)	1,742	1,676	1,666	1,745	1,690	1,690	1,729	1,736	1,745
Percent Load (% of maximum heat input at inlet temp)	59.3	61.8	67.4	69.7	73.5	73.5	81.9	80.9	80.5
Engine Compressor Discharge Pressure (psia)	148.0	143.5	148.3	164.9	161.1	161.1	190.0	189.0	189.0
Turbine Air Inlet Temperature (°F)	62.6	77.0	79.0	62.0	74.0	74.0	65.5	64.0	62.0
Compressor Discharge Temperature Sel. (°F)	652	673	679	681	694	694	718	718	713
Mean Turbine Exhaust Temperature (°F)	1037	1058	1096	1086	1101	1101	1073	1070	1070
SCR Ammonia Injection Rate (lbs/hr)	104.9	91.0	96.0	105.0	114.5	116.0	125.0	67.5	60.5
Pre-SCR Temperature (SCR inlet temperature, °F)	604	575	582	572	592	592	583	583	583
Post-SCR Temperature (SCR outlet temperature, °F)	622	605	612	610	617	617	618	615	615
Turbine Fuel Data (Residue Gas)									
Fuel Heating Value (Btu/lb, HHV)	23122	23122	23122	23122	23122	23122	23122	23122	23122
Fuel Specific Gravity	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982
Sulfur in Fuel (% weight, from ASTM D3246 analysis)	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	8646	8646	8646	8646	8646	8646	8646	8646	8646
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1034	1034	1034	1034	1034	1034	1034	1034	1034
Fuel Flow (KPPH)	44.70	44.80	48.58	52.63	53.75	53.75	61.27	60.76	60.76
Heat Input (MMBtu/hr, Higher Heat Value)	1033.6	1035.9	1123.3	1216.9	1242.8	1242.8	1416.7	1404.9	1404.9
Heat Input (MMBtu/hr, Lower Heat Value)	930.2	932.3	1010.9	1095.2	1118.5	1118.5	1275.0	1264.4	1264.4
Ambient Conditions									
Atmospheric Pressure ("Hg)	29.80	29.56	29.55	29.75	29.60	29.59	29.74	29.75	29.75
Temperature (°F): Dry bulb	62.0	80.5	81.2	64.0	78.0	79.8	68.6	65.2	64.9
(°F): Wet bulb	58.0	71.6	72.0	59.8	71.4	71.4	61.7	59.9	60.0
Humidity (lbs moisture/lb of air)	0.0092	0.0144	0.0146	0.0099	0.0148	0.0144	0.0100	0.0097	0.0098
Measured Emissions									
NO_X (ppmv, dry basis)	8.86	10.59	12.50	16.37	12.07	12.13	6.07	9.04	12.74
O_2 (% volume, dry basis)	15.11	15.01	14.62	14.40	14.43	14.39	14.47	14.43	14.39
CO_2 (% volume, dry basis)	3.35	3.32	3.48	3.71	3.75	3.75	3.71	3.66	3.64
F_o (fuel factor, range = 1.600-1.836 for NG)	1.73	1.77	1.80	1.75	1.73	1.74	1.73	1.77	1.79
Stack Volumetric Flow Rates									
via O_2 "F_d-factor" (SCFH, dry basis)	3.22E+07	3.18E+07	3.23E+07	3.38E+07	3.47E+07	3.45E+07	3.98E+07	3.92E+07	3.90E+07
via CO_2 "F_c-factor" (SCFH, dry basis)	3.19E+07	3.23E+07	3.34E+07	3.39E+07	3.43E+07	3.43E+07	3.95E+07	3.97E+07	3.99E+07
Calculated Emission Rates (via M-19 O_2 "F-factor")									
NO_X (ppmv, dry @ 15% O_2)	9.0	10.6	11.7	14.9	11.0	11.0	5.6	8.2	11.5
NO_X (ppmv @ 15% O_2, ISO Day)	9.5	11.8	13.0	15.8	12.4	12.3	5.9	8.7	12.3
NO_X (lbs/hr)	**34.1**	**40.8**	**49.8**	**66.3**	**50.0**	**50.0**	**28.9**	**42.9**	**60.7**

TABLE 5: Summary of Results
Full Load Testing
Unit 1B

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, JAR, JFR
Source: Unit 1B, a Westinghouse 501F Power Turbine

Test Number	Gas-BC-10	Gas-BC-11	Gas-BC-12		FDEP Permit Limits
Date	12/29/98	12/31/98	12/31/98		
Start Time	18:00	7:28	14:05		
Stop Time	21:45	8:34	15:11		
Turbine/Compressor Operation				*Averages*	
Generator Output (MW, CT generated power only)	169.3	180.34	168.60	*172.8*	
Heat Input (higher heating value, HHV)	1,728	1,771	1,736	*1,745*	
Turbine Capacity (Mfg.'s Curve, heat input vs. inlet temp)	1,728	1,802	1,715	*1,748*	
Percent Load (% of maximum heat input at inlet temp)	100.0%	98.3%	101.2%	*99.8%*	
Engine Compressor Discharge Pressure (psia)	213.7	225.05	215.15	*218.0*	
Turbine Air Inlet Temperature (°F)	65.7	49.0	68.7	*61.1*	
Compressor Discharge Temperature Sel. (°F)	762	743	767	*758*	
Mean Turbine Exhaust Temperature (°F)	1141	1123	1138	*1134*	
SCR Ammonia Injection Rate (lbs/hr)	231.3	231.03	216.12	*226.16*	
Pre-SCR Temperature (SCR inlet temperature, °F)	634	615	617	*622*	
Post-SCR Temperature (SCR outlet temperature, °F)	658	646	646	*650*	
Turbine Fuel Data (Natural Gas, FGT)					
Fuel Heating Value (Btu/lb, HHV)	23122	23122	23122	*23122*	
Fuel Specific Gravity	0.5982	0.5982	0.5982	*0.5982*	
Sulfur in Fuel (grains/100 SCF of fuel gas)	0.375	0.375	0.375	*0.375*	1
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	8646	8646	8646	*8646*	
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1034	1034	1034	*1034*	
Fuel Flow (KPPH, natural gas)	74.72	76.60	75.08	*75.47*	
Heat Input (MMBtu/hr, Higher Heat Value)	1727.7	1771.1	1736.0	*1744.9*	
Heat Input (MMBtu/hr, Lower Heat Value)	1554.9	1594.0	1562.4	*1570.4*	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.50	29.85	29.81	*29.72*	
Temperature (°F): Dry bulb	67.0	57.0	72.5	*65.5*	
(°F): Wet bulb	66.8	52.0	62.0	*60.3*	
Humidity (lbs moisture/lb of air)	0.0140	0.0070	0.0093	*0.0101*	
Measured Emissions					
NO_X (ppmv, dry basis)	12.47	12.88	13.18	*12.84*	
NO_X (ppmv, dry @ 15% O_2)	9.9	10.7	10.8	*10.5*	
NO_X (ppmv @ 15% O_2, ISO Day)	11.3	11.1	11.1	*11.2*	
CO (ppmv, dry basis)	0.67	0.84	0.87	*0.79*	
THC (ppmv, wet basis)	0.22	0.30	0.57	*0.36*	
PM (grams PM/DSCF exhaust gas)	1.82E-05	5.14E-05	2.00E-05	*2.99E-05*	
NH_3 (ppmv, dry basis from ion chromatography per FDEP)	4.38	3.71	4.48	*4.19*	10
NH_3 (ppmv, dry basis from on-site Nessler analysis)	5.82	6.75	5.87	*6.15*	10
Visible Emissions (% opacity)			0	0	10
H_2O (% volume, from Method 5 sample train)	9.14	8.05	7.97	8.38	
O_2 (% volume, dry basis)	13.50	13.78	13.69	*13.66*	
CO_2 (% volume, dry basis)	4.32	3.93	4.10	*4.12*	
F_o (fuel factor, range = 1.600-1.836 for NG)	1.71	1.81	1.76	*1.76*	
Stack Volumetric Flow Rates					
via O_2 "F_d-factor" (SCFH, dry basis)	4.22E+07	4.50E+07	4.35E+07	*4.35E+07*	
via CO_2 "F_c-factor" (SCFH, dry basis)	4.14E+07	4.66E+07	4.38E+07	*4.39E+07*	
Calculated Emission Rates (via M-19 O_2 "F-factor")					
NO_X (lbs/hr)	62.8	71.7	68.9	*67.8*	72.69†
CO (lbs/hr)	2.06	2.85	2.77	*2.56*	77
THC (lbs/hr)	0.43	0.63	1.13	*0.73*	10.4
PM (lbs/hr)	1.69	5.28	1.93	*2.97*	15.6
SO_2 (lbs/hr, based on fuel flow and fuel sulfur)	1.63	1.67	1.64	*1.65*	4.7

† Permit Limit based upon actual average turbine air inlet temperature during testing

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida

Initial Compliance Test Report
for
No. 2 Fuel Oil Fueled Stack Emissions

on
Power Block 1

consisting of
Units 1A and 1B, two Westinghouse 501F Combined Cycle Combustion Turbines

at the
Hines Energy Complex

in
Polk County, Florida

Prepared for
Florida Power Corporation

May 1999

Cubix Job No. 4911

Prepared by

Cubix Corporation
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INTRODUCTION

Emission testing was conducted on Power Block 1, which consists of two combined cycle combustion turbines manufactured by Siemens Westinghouse Power Corporation. These units, used to generate power, were recently installed at the Hines Energy Complex located near Fort Meade in Polk County, Florida. Florida Power Corporation (FPC) owns and operates this facility. This report documents the testing of each combustion turbine while fueled with No. 2 fuel oil. A separate report was previously provided for the testing of the units while fueled with natural gas. The testing was conducted by Cubix Corporation, Southeast Regional Office on April 1 through 2 and April 11 through 12, 1999.

The purpose of this testing was to determine the status of initial compliance for combustion turbine emissions with the permit limits set forth by the Florida Department of Environmental Protection (FDEP), Permit Numbers PSD-FL-195A and PA-92-33. Additionally, the emissions were measured to determine compliance with the Environmental Protection Agency (EPA) Code of Federal Regulations, Title 40, Part 60, (40 CFR 60) Subpart GG "Standards of Performance for Stationary Gas Turbines". The tests followed the procedures set forth in 40 CFR 60, Appendix A, Methods 1, 2, 3a, 4, 5, 9, 10, 19, 20, and 25a.

Each turbine's exhaust was analyzed for oxides of nitrogen (NO_X), carbon monoxide (CO), total hydrocarbon compounds (THC), oxygen (O_2), and carbon dioxide (CO_2) using continuous instrumental monitors. Particulate matter (PM) samples were collected iso-kinetically using a combined hot/cold manual sampling train. Visible emissions (VE) were determined by a certified observer. Analysis of the No. 2 fuel oil was provided by Intertek Testing Services laboratory of Tampa, Florida using American Society of Testing and Materials (ASTM) test methods. Table 1 provides background data pertinent to these tests.

This test report has been reviewed and approved for submittal to the FDEP by the following representatives:

Cubix Corporation	Florida Power Corporation

TABLE 1
BACKGROUND DATA

Owner/Operator:	**Florida Power Corporation** One Power Plaza, 263 13th Avenue South, BB1A St. Petersburg, Florida 33701-5511 (727) 826-4258 TEL (727) 826-4216 FAX Attn: Scott Osbourn, Sr. Environmental Engineer
Testing Organization:	**Cubix Corporation, SE Regional Office** 4536 NW 20th Drive Gainesville, Florida 32605 (352) 378-0332 TEL (352) 378-0354 FAX Attn: Leonard Brenner, Project Manager
Test Participants:	**Florida Power Corporation** Scott Osbourn J. William Agee **FDEP** William A. Proses **Cubix Corporation** Leonard Brenner Dwight Dindial Roger Paul Osier

Test Dates:	Unit 1B: April 1 and 2, 1999 Unit 1A: April 11 and 12, 1999
Facility Location:	Hines Energy Complex 7700 County Road 555 Bartow, Florida 33830 Latitude: 27°47'19" North Longitude: 81°52'10" West
Process Description:	Two combined cycle combustion turbines (CTs) are used to generate electrical power. Each unit, a Westinghouse Model 501F, consists of a single shaft gas combustion turbine directly connected to a 60 Hz power generator. Each turbine is equipped with an unfired heat recovery steam generator (HRSG) to drive a steam turbine for additional power generation. The facility is designed to provide either No. 2 fuel oil or natural gas fuel to each combustion turbine.
Regulatory Application:	Florida Department of Environmental Protection (FDEP) Permit Nos. PSD-FL-195A and PA-92-33 and EPA New Source Performance Standards (NSPS) 40 CFR 60, Subpart GG.
Emission Sampling Points:	Each exhaust stack is a circular stack 130' tall with a diameter of 216". Four 6" sample ports are located 90° from each other at 107' above grade. Access to the sample ports are provided with a permanently mounted steel grate service platform equipped with a caged safety ladder.
Test Methods:	EPA Method 1 for oxygen (O_2) and particulate matter (PM) traverse point locations. EPA Method 2 for stack gas differential pressure measurements during PM sampling. EPA Method 3a for carbon dioxide (CO_2) concentrations. EPA Method 4 for stack gas moisture content.

Test Methods (Cont.'):

EPA Method 5 for particulate matter (PM) concentrations.

EPA Method 9 for visible emissions (VE) measurements determined as opacity from a certified observer.

EPA Method 10 for carbon monoxide (CO) concentrations.

EPA Method 19 for the calculation of volumetric flow and pollutant mass emission rates.

EPA Method 20 for oxides of nitrogen (NO_X) and oxygen (O_2) concentrations.

EPA Method 25a for total hydrocarbon compound (THC) concentrations.

American Society of Testing and Materials (ASTM) Test Method D2622 for total sulfur analysis of the fuel oil.

ASTM Test Method D4629 for determination of fuel bound nitrogen in the fuel oil.

ASTM Test Method D240 for higher heating value of the fuel oil.

ASTM Test Method D5291 for carbon, hydrogen, oxygen ultimate analysis used for calculation of fuel specific "F-factors".

SUMMARY OF RESULTS

Florida Power Corporation (FPC) owns and operates the Hines Energy Complex in Polk County, Florida. At this facility two Westinghouse combined cycle combustion turbines, each equipped with an unfired heat recovery steam generator (HRSG), are used to generate electrical power. The combustion turbines are designated as Unit 1A and Unit 1B by FPC. Stack emissions from these units, while fueled with No. 2 fuel oil, are the subject of this report. Unit emissions, while fueled with natural gas, were previously reported.

A sampling traverse for changes in O_2 concentration (stratification) within the exhaust stack on each unit was conducted previously while fueled with natural gas. The first step in the test matrix for each unit consisted of conducting an initial O_2 sampling traverse of the combustion turbine/heat recovery steam generator (CT/HRSG) exhaust stack. Each turbine was set to the lowest load representative of normal operation, approximately 90 megawatts (MW), while operating under dry, low NO_X combustion and with Selective Catalytic Reduction (SCR) operating. O_2 concentrations were measured at 48 traverse points within the CT/HRSG stack to determine the eight points of lowest O_2 concentration. This initial traverse was conducted on each CT/HRSG stack. No significant stratification was found in either exhaust stack; therefore, all subsequent tests were conducted at the eight most convenient traverse points on each unit.

Cubix conducted three test runs at each of four load conditions across the operational range of the combustion turbine (~85 MW, ~110 MW, ~135 MW, and full load at ~155 MW). Each reduced load test run was 20 minutes in duration (8 sample points, 150 seconds per point). Full load is defined as 90 to 100% of the maximum permitted capacity, expressed as heat input, determined from the Westinghouse performance curve of heat input versus turbine inlet temperature for the unit. NO_X, O_2, and CO_2 were continuously monitored at all load conditions. Additional full load measurements included CO and THC using continuous instrumental monitors and iso-kinetic sampling for collection of PM samples. The full load test runs were 1 hour in duration for all constituents. A one-hour VE test was conducted simultaneously with one of the full load test runs. This test matrix was performed on both CT units.

Table 2, the executive summary, signifies the performance for each unit during the full load testing. These performance results are an average of the three full load test runs for each unit. These emissions are compared to the permit limits set forth in FDEP Permit Nos. PSD-FL-195A and PA-92-33.

TABLE 2
Fuel Oil Executive Summary

Parameter	Unit 1A Westinghouse 501F Turbine	Unit 1B Westinghouse 501F Turbine	NSPS/FDEP Permit Limits
Percent Load (of capacity as heat input)	102.9%	102.7%	90 to 100%
NO_x (lbs/hr at 76°F inlet temperature)	234.0	-	294.92
NO_x (lbs/hr at 78°F inlet temperature)	-	206.0	293.38
VOC (lbs/hr, from THC measurements)	0.68	0.30	19.0
CO (lbs/hr)	4.24	3.78	93
PM/PM_{10} (lbs/hr)	26.0	27.2	44.8
SO_2 (lbs/hr)	5.11	5.25	94.0
Visible Emissions (% opacity)	2.2%	5%	20%

Tables 3 and 4 represent the Unit 1A test results for full load fuel oil (FO) and reduced load FO testing, respectively. These tabular summaries contain all pertinent operational parameters, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of parts per million by volume (ppmv) on a dry basis, ppmv corrected to 15% excess O_2, and ppmv corrected to 15% excess O_2 and ISO conditions. The EPA defines ISO conditions as ambient atmospheric conditions of 59 degrees Fahrenheit (°F) temperature, 101.3 kilopascals (kPa) pressure, and 60% relative humidity. CO concentrations were determined on ppmv, dry basis. Volatile organic compound (VOC) concentrations were determined from THC measurements and were determined on a ppmv, wet basis as methane. Concentrations of PM were determined in units of grams per dry standard cubic feet (grams PM/DSCF). Mass emission rates for NO_X, CO, VOC, PM, and SO_2 are reported in terms of pounds per hour (lbs/hr). As stated in the test matrix above, only NO_X concentrations and emissions were applicable for the reduced load tests.

Tables 5 and 6 represent the Unit 1B test results for full load FO and reduced load FO testing, respectively. These tabular summaries contain all pertinent operational parameters, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of ppmv on a dry basis, ppmv at 15% excess O_2, and ppmv at 15% excess O_2 and ISO conditions. CO concentrations were determined on ppmv, dry basis. VOC concentrations were determined from THC measurements and were determined on a ppmv, wet basis as methane. Concentrations of PM were determined in units of grams PM/DSCF. Mass emission rates for NO_x, CO, VOC, PM, and SO_2 are reported in terms of lbs/hr.

Volumetric flow and mass emission rates were determined by stoichiometric calculation (EPA Method 19) based on measurements of diluent gas (O_2 or CO_2) concentrations, "F-factors" determined from fuel composition, and unit fuel flow rates. Examples of iso-kinetic calculations, emission rate calculations, and other calculations necessary for the presentation of the results of this section are contained in Appendix B.

The fuel sulfur content analyses, concentration percent weight, is contained in Appendix C of this report. A fuel oil sample was collected during the testing for each unit and shipped to Intertek Testing Services of Tampa, Florida for analysis. The fuel was analyzed for total fuel sulfur content by ASTM Method D2622. The SO_2 emission rates, reported in lbs/hr, were calculated from the results of these analyses and the measured fuel flow rates recorded during the tests.

The fuel bound nitrogen (FBN) analyses, concentration in parts per million (ppm) by weight, is contained in Appendix C of this report. A fuel sample was collected and shipped to the laboratory designated above for analysis. The fuel was analyzed for FBN by ASTM Method D4629. Results of FBN were below 150 ppm, the breakpoint value used for correction of exhaust NO_X emissions.

Visible emission observations of each CT/HRSG exhaust stack per EPA Method 9 were performed by an observer certified by Eastern Technical Associates of Raleigh, North Carolina. A one-hour visible emissions test run was conducted on each unit. VE were an average of 2.2% opacity on Unit 1A in the highest six-minute average and 5% opacity on Unit 1B in the highest six-minute average. No VE greater than 5% opacity was observed during the tests.

Appendix A contains all field data sheets used during these tests as well as the particulate matter analysis worksheets. Appendix B contains examples of all calculations necessary for the reduction of the data presented in this report. Appendix C contains the fuel analysis and Cubix's fuel calculation worksheet. Quality Assurance Activities are documented in Appendix D. Certificates of calibrations are contained in Appendix E of this report. Copies of the reference method strip chart records obtained during these tests are available in Appendix F of this report. Appendix G contains the "Visible Emissions Observation Forms" and the observer certifications. Appendix H contains the operational data provided by FPC during the test runs. The FDEP facility permit is presented in Appendix I for reference purposes.

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, DLD
Source: Unit 1A, a Westinghouse 501F Power Turbine

TABLE 3: Summary of Results
Full Load FO Tests
Unit 1A

Test Run Number	Oil-AC-1	Oil-AC-2	Oil-AC-3		
Date	4/11/99	4/11/99	4/11/99		
Start Time	18:28	20:14	22:28		FDEP
Stop Time (24 hour clock	19:28	21:20	23:28		Permit
Power Turbine Operation				*Averages*	Limits
Generator Output (MW, simple cycle mode)	153.8	156.3	158.1	*156.1*	
Heat Input (MMBtu/hr, based on GHV)	1795	1818	1835	*1816*	
Turbine Capacity (Mfg.'s Curve, heat input vs. capacity)	1746	1763	1788	*1766*	
Percent Load (% of maximum heat input at inlet temp)	102.9%	103.1%	102.6%	*102.9%*	
Engine Compressor Discharge Pressure (psia)	207.5	209.4	211.8	*209.5*	
Turbine Air Inlet Temperature (°F)	79.8	76.2	71.2	*75.7*	
Mean Turbine Exhaust Temperature (°F)	1106	1103	1100	*1103*	
Water Injection Stage A & B Flow (gpm)	97.2	98.8	98.8	*98.3*	
Water to Fuel Ratio (lbs H_2O/lb fuel)	0.6	0.6	0.6	*0.6*	
Water Injection Stage A & B Flow (KPPH)	48.6	49.4	49.4	*49.2*	
Water to Fuel Ratio (lbs H_2O/lb fuel, calculated)	0.539	0.541	0.536	*0.538*	
Fuel Data (No. 2 Fuel Oil)					
O_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	9151	9151	9151	*9151*	
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	1389	1389	1389	*1389*	
O_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	9190	9190	9190	*9190*	
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	1420	1420	1420	*1420*	
Fuel Flow (KPPH)	90.25	91.40	92.24	*91.30*	
Total Sulfur in Fuel (% weight)	0.0028	0.0028	0.0028	*0.0028*	0.05
Fuel Bound Nitrogen (ppm, weight)	97	97	97	*97*	
Fuel Heating Value (Btu/lb, GHV)	19,892	19,892	19,892	*19,892*	
Heat Input (MMBtu/hr, based on GHV)	1795.3	1818.2	1834.9	*1816.1*	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.66	29.71	29.73	*29.70*	
Temperature (°F): Dry bulb	82.0	74.8	72.3	*76.4*	
(°F): Wet bulb	72.9	71.6	71.4	*72.0*	
Humidity (lbs moisture/lb of air)	0.0150	0.0157	0.0161	*0.0156*	
Cubix Measurements					
NOx (ppmv, dry basis)	45.24	41.31	38.55	*41.70*	
NO_X (ppmv, dry @ 15% O_2)	36.0	32.9	30.7	*33.2*	
NO_X (ppmv @ 15% O_2, ISO Day)	40.2	37.5	35.8	*37.8*	
CO (ppmv, dry basis)	1.25	1.25	1.23	*1.24*	
O_2 (% volume, dry basis)	13.49	13.50	13.50	*13.50*	
CO_2 (% volume, dry basis)	5.63	5.62	5.72	*5.66*	
THC (ppmv as CH_4, wet basis)	0.26	0.33	0.36	*0.32*	
PM (grams PM/DSCF exhaust gas)	2.32E-04	2.93E-04	2.29E-04	*2.51E-04*	
Visible Emissions (% opacity)	2.2			2.2	20
H_20 (% volume)	7.50	7.95	9.34	*8.26*	
F_c (Fuel factor = 1.260 - 1.413 for distillate oil)	1.32	1.32	1.29	*1.31*	
Stack Volumetric Flow Rates (from calculated "F-factors")					
via O_2 "F-factor" (SCFH, dry basis)	4.63E+07	4.70E+07	4.74E+07	*4.69E+07*	
via CO_2 "F-factor" (SCFH, dry basis)	4.43E+07	4.49E+07	4.46E+07	*4.46E+07*	
Calculated Emission Rates (via M-19 "F-factors")					
NO_X (lbs/hr)	250	232	218	*234*	294.92[1]
CO (lbs/hr)	4.21	4.27	4.24	*4.24*	93.0
THC (lbs/hr)	0.54	0.70	0.78	*0.68*	19.0
PM/PM_{10} (lbs/hr, including H_2SO_4 mist)	23.7	30.3	23.9	*26.0*	44.8
SO_2 (lbs/hr, based on fuel flow and fuel S)	5.05	5.11	5.16	*5.11*	94.0

[1] Permit Limit based upon actual average turbine air inlet temperature during testing

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, DLD
Source: Unit 1A, a Westinghouse 501F Power Turbine

TABLE 4: Summary of Results
Reduced Load FO Testing
Unit 1A

Test Run No.	Oil-AC-4	Oil-AC-5	Oil-AC-6	Oil-AC-7	Oil-AC-8	Oil-AC-9	Oil-AC-10	Oil-AC-11	Oil-AC-12
Date	4/11-12/99	4/12/99	4/12/99	4/12/99	4/12/99	4/12/99	4/12/99	4/12/99	4/12/99
Start Time	23:55	00:24	00:52	01:30	01:59	02:28	04:00	04:29	04:57
Stop Time	00:16	00:44	01:14	01:50	02:19	02:48	04:20	04:49	05:17
Power Turbine Operation	~136 MW Generator Output			~111 MW Generator Output			~85 MW Generator Output		
Generator Output (MW, simple cycle mode)	136.0	135.9	136.6	111.5	112.3	111.3	84.3	85.8	85.0
Heat Input (MMBtu/hr, based on GHV)	1600.6	1597.0	1609.5	1354.9	1362.6	1359.8	1118.4	1128.9	1126.5
Turbine Capacity (Mfg.'s Curve, heat input vs. capacity)	1787	1789	1791	1784	1794	1794	1794	1794	1794
Percent Load (% of maximum heat input at inlet temp)	89.6%	89.3%	89.8%	75.9%	76.0%	75.8%	62.3%	62.9%	62.8%
Engine Compressor Discharge Pressure (psia)	192.1	192.6	192.6	172.4	172.4	171.8	156.3	155.7	155.7
Turbine Air Inlet Temperature (°F)	71.5	71.0	70.5	72.0	70.0	70.0	70.0	70.0	70.0
Mean Turbine Exhaust Temperature (°F)	1068	1065	1065	1037	1039	1034	969	969	969
Water Injection Stage A & B Flow (gpm)	70.4	71.5	71.5	46.0	46.0	47.0	28.2	28.2	28.2
Water to Fuel Ratio (lbs H_2O/lb fuel)	0.5	0.5	0.5	0.4	0.4	0.4	0.2	0.2	0.2
Water Injection Stage A & B Flow (KPPH)	35.2	35.7	35.8	23.0	23.0	23.5	14.1	14.1	14.1
Water to Fuel Ratio (lbs H_2O/lb fuel, calculated)	0.437	0.445	0.442	0.338	0.336	0.344	0.251	0.249	0.249
Fuel Data (No.2 Fuel Oil)									
O_2 "F-factor" (DSCFex/MMBtu fuel burned) Published	9151	9151	9151	9151	9151	9151	9151	9151	9151
CO_2 "F-factor" (DSCFex/MMBtu fuel burned) Published	1390	1390	1390	1390	1390	1390	1390	1390	1390
O_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	9190	9190	9190	9190	9190	9190	9190	9190	9190
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	1420	1420	1420	1420	1420	1420	1420	1420	1420
Fuel Flow (KPPH)	80.48	80.30	80.93	68.13	68.51	68.37	56.23	56.76	56.64
Total Sulfur in Fuel (% weight)	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029	0.0029
Fuel Bound Nitrogen (ppm by weight)	92	92	92	92	92	92	92	92	92
Fuel Heating Value (Btu/lb, GHV)	19,889	19,889	19,889	19,889	19,889	19,889	19,889	19,889	19,889
Heat Input (MMBtu/hr, based on GHV)	1600.6	1597.0	1609.5	1354.9	1362.6	1359.8	1118.4	1128.9	1126.5
Ambient Conditions									
Atmospheric Pressure ("Hg)	29.71	29.72	29.70	29.70	29.70	29.69	29.68	29.68	29.69
Temperature (°F): Dry bulb	72.1	71.8	71.0	71.1	70.3	70.3	70.6	71.2	71.3
(°F): Wet bulb	71.2	71.2	71.0	70.2	69.9	69.9	69.8	70.0	69.9
Humidity (lbs moisture/lb of air)	0.0160	0.0161	0.0161	0.0154	0.0154	0.0154	0.0153	0.0153	0.0152
Cubix Measurements									
NO_x (ppmv, dry basis)	40.09	38.97	38.43	31.63	30.74	29.42	24.92	24.78	24.56
O_2 (% volume, dry basis)	13.88	13.88	13.87	14.38	14.42	14.45	15.26	15.22	15.22
CO_2 (% volume, dry basis)	5.29	5.32	5.36	4.96	4.95	4.95	4.20	4.30	4.30
F_o (fuel factor, range = 1.260 - 1.413 for FO)	1.33	1.32	1.31	1.31	1.31	1.30	1.34	1.32	1.32
Stack Volumetric Flow Rates (from calculated "F-factors")									
via O_2 "F-factor" (SCFH, dry basis)	4.38E+07	4.37E+07	4.40E+07	3.99E+07	4.04E+07	4.05E+07	3.81E+07	3.82E+07	3.81E+07
via CO_2 "F-factor" (SCFH, dry basis)	4.30E+07	4.26E+07	4.26E+07	3.88E+07	3.91E+07	3.90E+07	3.78E+07	3.73E+07	3.72E+07
Calculated Emission Rates (via M-19 "F-factors")									
NO_x (ppmv, dry @ 15% O_2)	33.7	32.8	32.3	28.6	28.0	26.9	26.1	25.7	25.5
NO_x (ppmv, dry @ 15% O_2, ISO Day)	39.1	38.1	37.6	32.9	32.3	31.1	30.0	29.6	29.3
NO_x (lbs/hr)	**210**	**203**	**202**	**151**	**148**	**142**	**113**	**113**	**112**

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, DLD
Source: Unit 1B, a Westinghouse 501F Power Turbine

TABLE 5: Summary of Results
Full Load FO Tests
Unit 1B

Test Run Number	Oil-BC-4	Oil-BC-5	Oil-BC-6		
Date	4/1/99	4/1/99	4/1/99		
Start Time	13:10	15:50	17:50		FDEP
Stop Time	14:10	16:50	18:50		Permit
Power Turbine Operation				*Averages*	Limits
Generator Output (MW, simple cycle mode)	153.0	153.8	159.1	*155.3*	
Heat Input (MMBtu/hr, based on GHV)	1781	1790	1832	*1801*	
Turbine Capacity (Mfg.'s Curve, heat input vs. capacity)	1740	1736	1786	*1754*	
Percent Load (% of maximum heat input at inlet temp)	102.4%	103.1%	102.6%	*102.7%*	
Engine Compressor Discharge Pressure (psia)	207.9	207.2	212.0	*209.0*	
Turbine Air Inlet Temperature (°F)	81.0	81.8	71.6	*78.1*	
Mean Turbine Exhaust Temperature (°F)	1103	1109	1099	*1104*	
Water Injection Stage A & B Flow (gpm)	97.20	98.26	96.30	*97.25*	
Water to Fuel Ratio (lbs H_2O/lb fuel)	0.6	0.6	0.6	*0.6*	
Water Injection Stage A & B Flow (KPPH)	48.62	49.15	48.17	*48.65*	
Water to Fuel Ratio (lbs H_2O/lb fuel, calculated)	0.543	0.546	0.523	*0.537*	
Fuel Data (No. 2 Fuel Oil)					
O_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	9151	9151	9151	*9151*	
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	1390	1390	1390	*1390*	
O_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	9190	9190	9190	*9190*	
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	1420	1420	1420	*1420*	
Fuel Flow (KPPH)	89.55	90.00	92.12	*90.56*	
Total Sulfur in Fuel (% weight)	0.0029	0.0029	0.0029	*0.0029*	0.05
Fuel Bound Nitrogen (ppm by weight)	92	92	92	*92*	
Fuel Heating Value (Btu/lb, GHV)	19,889	19,889	19,889	*19,889*	
Heat Input (MMBtu/hr, based on GHV)	1781.1	1790.0	1832.2	*1801.1*	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.69	29.64	29.65	*29.66*	
Temperature (°F): Dry bulb	87.0	85.0	76.2	*82.7*	
(°F): Wet bulb	74.0	73.0	70.3	*72.4*	
Humidity (lbs moisture/lb of air)	0.0148	0.0144	0.0144	*0.0145*	
Cubix Measurements					
NOx (ppmv, dry basis)	38.88	38.14	36.78	*37.93*	
NO_X (ppmv, dry @ 15% O_2)	30.3	29.6	28.7	*29.6*	
NO_X (ppmv @ 15% O_2, ISO Day)	33.5	32.5	32.3	*32.8*	
CO (ppmv, dry basis)	1.24	1.10	1.09	*1.14*	
O_2 (% volume, dry basis)	13.34	13.30	13.34	*13.33*	
CO_2 (% volume, dry basis)	5.57	5.56	5.48	*5.54*	
THC (ppmv as CH_4, wet basis)	0.26	0.12	0.05	*0.14*	
PM (grams PM/DSCF exhaust gas)	2.51E-04	2.97E-04	2.65E-04	*2.71E-04*	
Visible Emissions (% opacity)		5.0		5.0	20
H_2O (% volume)	8.97	9.12	9.25	*9.11*	
F_o (Fuel factor = 1.260 - 1.413 for distillate oil)	1.36	1.37	1.38	*1.37*	
Stack Volumetric Flow Rates (from calculated "F-factors")					
via O_2 "F-factor" (SCFH, dry basis)	4.51E+07	4.50E+07	4.64E+07	*4.55E+07*	
via CO_2 "F-factor" (SCFH, dry basis)	4.44E+07	4.48E+07	4.65E+07	*4.52E+07*	
Calculated Emission Rates (via M-19 "F-factors")					
NO_X (lbs/hr)	209	205	204	*206*	293.38*
CO (lbs/hr)	4.06	3.60	3.68	*3.78*	93.0
THC (lbs/hr)	0.54	0.25	0.11	*0.30*	19.0
PM/PM_{10} (lbs/hr, including H_2SO_4 mist)	24.9	29.5	27.1	*27.2*	44.8
SO_2 (lbs/hr, based on fuel flow and fuel S)	5.19	5.22	5.34	*5.25*	94.0

* Permit Limit based upon actual average turbine air inlet temperature during testing

Testing by Cubix Corporation, - Austin, Texas - Gainesville, Florida

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, RPO, DLD
Source: Unit 1B, a Westinghouse 501F Power Turbine

TABLE 6: Summary of Results
Reduced Load FO Testing
Unit 1B

Test Run No.	Oil-BC-1	Oil-BC-2	Oil-BC-3	Oil-BC-7	Oil-BC-8	Oil-BC-9	Oil-BC-10	Oil-BC-11	Oil-BC-12
Date	4/1/99	4/1/99	4/1/99	4/2/99	4/2/99	4/2/99	4/2/99	4/2/99	4/2/99
Start Time	08:55	09:28	10:04	08:10	08:45	09:18	10:20	10:53	11:25
Stop Time	09:15	09:48	10:24	08:30	09:05	09:39	10:40	11:13	11:45
Power Turbine Operation	~85 MW Generator Output			~132 MW Generator Output			~110 MW Generator Output		
Generator Output (MW, simple cycle mode)	86.0	85.2	85.3	131.9	131.9	131.5	110.9	110.2	109.1
Heat Input (MMBtu/hr, based on GHV)	1133.6	1123.9	1129.1	1539.5	1547.3	1547.1	1352.2	1343.9	1330.6
Turbine Capacity (Mfg.'s Curve, heat input vs. capacity)	1789	1774	1769	1804	1804	1804	1787	1769	1769
Percent Load (% of maximum heat input at inlet temp)	63.4%	63.3%	63.8%	85.4%	85.8%	85.8%	75.7%	76.0%	75.2%
Engine Compressor Discharge Pressure (psia)	155.2	155.2	155.2	189.6	189.6	189.6	171.6	171.0	170.5
Turbine Air Inlet Temperature (°F)	71.0	74.0	75.0	68.0	68.0	68.0	71.5	75.0	75.0
Mean Turbine Exhaust Temperature (°F)	995	994	995	1041	1043	1046	1038	1041	1038
Water Injection Stage A & B Flow (gpm)	28.3	28.3	28.3	63.2	63.2	64.4	44.2	44.2	44.2
Water to Fuel Ratio (lbs H_2O/lb fuel)	0.3	0.3	0.3	0.5	0.5	0.5	0.4	0.4	0.4
Water Injection Stage A & B Flow (KPPH)	14.2	14.2	14.2	31.6	31.6	32.2	22.1	22.1	22.1
Water to Fuel Ratio (lbs H_2O/lb fuel, calculated)	0.248	0.251	0.249	0.408	0.406	0.414	0.325	0.327	0.331
Fuel Data (No.2 Fuel Oil)									
O_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	9151	9151	9151	9151	9151	9151	9151	9151	9151
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, calculated)	1389	1389	1389	1389	1389	1389	1389	1389	1389
O_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	9190	9190	9190	9190	9190	9190	9190	9190	9190
CO_2 "F-factor" (DSCFex/MMBtu fuel burned, published)	1420	1420	1420	1420	1420	1420	1420	1420	1420
Fuel Flow (KPPH)	56.99	56.50	56.76	77.40	77.79	77.78	67.98	67.56	66.89
Total Sulfur in Fuel (% weight)	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
Fuel Bound Nitrogen (ppm by weight)	97	97	97	97	97	97	97	97	97
Fuel Heating Value (Btu/lb, GHV)	19,892	19,892	19,892	19,892	19,892	19,892	19,892	19,892	19,892
Heat Input (MMBtu/hr, based on GHV)	1133.6	1123.9	1129.1	1539.5	1547.3	1547.1	1352.2	1343.9	1330.6
Ambient Conditions									
Atmospheric Pressure ("Hg)	29.76	29.76	29.76	29.74	29.74	29.75	29.75	29.75	29.75
Temperature (°F): Dry bulb	78.3	79.2	83.1	71.0	71.8	72.2	76.3	78.2	81.8
(°F): Wet bulb	71.7	72.1	73.0	70.4	71.2	71.7	72.8	73.8	75.0
Humidity (lbs moisture/lb of air)	0.0149	0.0150	0.0148	0.0156	0.0160	0.0163	0.0163	0.0166	0.0168
Cubix Measurements									
NO_X (ppmv, dry basis)	26.40	25.44	25.72	29.62	31.39	32.46	31.44	32.84	32.93
O_2 (% volume, dry basis)	15.14	15.15	15.12	14.11	14.07	14.03	14.48	14.48	14.46
CO_2 (% volume, dry basis)	4.37	4.37	4.37	5.15	5.19	5.20	4.84	4.93	4.89
F_o (fuel factor, range = 1.260 - 1.413 for FO)	1.32	1.32	1.32	1.32	1.32	1.32	1.33	1.30	1.32
Stack Volumetric Flow Rates (from calculated "F-factors")									
via O_2 "F-factor" (SCFH, dry basis)	3.76E+07	3.74E+07	3.74E+07	4.34E+07	4.33E+07	4.31E+07	4.03E+07	4.00E+07	3.95E+07
via CO_2 "F-factor" (SCFH, dry basis)	3.60E+07	3.57E+07	3.59E+07	4.15E+07	4.14E+07	4.13E+07	3.88E+07	3.79E+07	3.78E+07
Calculated Emission Rates (via M-19 "F-factors")									
NO_X (ppmv, dry @ 15% O_2)	27.0	26.1	26.3	25.7	27.1	27.9	28.9	30.2	30.2
NO_X (ppmv, dry @ 15% O_2, ISO Day)	30.8	29.5	29.5	30.0	31.8	32.9	33.7	35.1	35.2
NO_X (lbs/hr)	**119**	**114**	**115**	**153**	**162**	**167**	**151**	**157**	**155**

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida

PROCESS DESCRIPTION

Florida Power Corporation owns and operates the Hines Energy Complex in Polk County, Florida. Two recently installed combined cycle power generation units were manufactured by Siemens Westinghouse Power Corporation, each consists of a combustion turbine, a heat recovery steam generator, and a supplemental steam turbine. Emission testing was conducted on the units to determine their compliance status with state and federal regulations. This section of the test report provides a brief description of the units.

This facility is designated as Power Block 1, a two unit combined cycle power plant, Units 1A and 1B. The main body of each unit consists of a single shaft combustion turbine directly coupled to a 60 Hz generator. A heat recovery steam generator (HRSG) is installed just downstream of each turbine exhaust to recover additional energy (heat) from the process. The steam produced from the HRSGs may then drive a steam turbine which generates additional electricity. The facility is designed to provide two fuels to the combustion turbines: No. 2 fuel oil or natural gas. During fuel oil operation, NO_X emissions are controlled on each turbine with water injection. While firing with fuel oil, each CT has a full load rating of approximately 165 MW in simple cycle mode and a heat input of 1846 MMBtu/hr, based upon the higher heat value, at site conditions of 59 °F inlet air temperature. FDEP has allowed the manufacturer's curve of heat input vs. turbine inlet temperature to define full load heat input for each CT (see Appendices H and I for curve data).

The circular CT/HRSG exhaust stacks were utilized for exhaust emission measurements of the turbine testing. The exhaust stack dimensions are depicted in the stack diagrams of Appendix A. Each stack is 130 feet tall and has a diameter of 216 inches. Four six-inch diameter sample ports are spaced perpendicular to each other. These ports are approximately 23 feet from the stack exit (107 feet above ground level). A metal grate service platform, a caged safety ladder, and a metal stairway were installed to provide access to the sample ports.

Operational data was obtained by FPC personnel from control panel instrumentation. Data was collected at 15 minute intervals (during the entire test period) and averaged over each test run period. The operational data reported in the summary tables is an average of the readings recorded during the gaseous test period of each run. All operational data sheets are located in Appendix H.

ANALYTICAL TECHNIQUES

Emissions from two combustion turbines were measured at the FPC Hines Energy Complex located in Polk County, Florida. These tests were performed by Cubix Corporation on April 1 and 2, 1999, and April 11 and 12, 1999, in order to determine the initial compliance status with regard to permitted emission limits while fueled with No. 2 fuel oil . This section of the report describes the analytical techniques and procedures used during these tests.

The sampling and analysis procedures used during these tests conformed with those outlined in The Code of Federal Regulations, 40 CFR 60, Appendix A, Methods 1, 2, 3a, 4, 5, 9, 10, 19, 20, and 25a. The stack gas analyses for NO_X, CO, THC, O_2 and CO_2 were performed by continuous instrumental monitors. Exhaust gas analyses were performed on a dry basis for all compounds except THC. Table 7 lists the instruments and detection principles used for these analyses.

The test matrix for each turbine consisted of three sixty-minute (or greater) test runs at full load and three 20 minute test runs at each of three reduced loads. Per EPA Method 20 requirements, an initial O_2-traverse was conducted previously when the units were fueled with natural gas. Forty-eight points in the stack cross section, twelve sample points in each of four ports, were measured for 140 seconds at each point. The sampling time at each point was determined from the sampling systems response time (see *Quality Assurance Activities).* No stratification of oxygen was found in either exhaust stack. Therefore, eight random points were sampled for 150 seconds each, 7.5 minutes each for full load testing, in the subsequent test runs. During reduced loads (~85 MW, ~110 MW, and ~135 MW), NO_X, CO_2, and O_2 stack gases were measured using continuous instrumental monitors. Stack gases were analyzed for NO_X, CO, THC, O_2, and CO_2 by continuous instrumental monitors during the full load test runs (~155 MW). All gas analyses were performed on a dry basis except hydrocarbons. Three 60 minute test runs were conducted at base load for all components. A 60 minute VE test was conducted concurrently with one of the full load test runs on each unit.

Gaseous Emission Testing

Provisions were made to introduce the calibration gases to the instrumental monitors via two paths: 1) directly to the instruments via the sample manifold quick-connects and rotameters, and 2) through the complete sampling system including the sample probe, filter, heat trace, condenser, manifold, and rotameters. The former method was used for quick, convenient calibration checks. The latter method was used to demonstrate that the sample was not altered due to leakage, reactions, or adsorption within the sampling system (sample system bias check). A NO_X standard calibration gas was introduced into the NO_X analyzer directly. Then the response from the NO_X analyzer was noted as the calibration gas was introduced at the probe. Any difference between the two responses in the instrument was attributed to the bias of the sample system. Following the span gas bias check, a zero gas bias check was performed on the NO_X analyzer using nitrogen to check for any zero bias of the sample system. In accordance with EPA Method 3a this span and zero bias check procedure was repeated for the CO_2 and O_2 analyzers. This procedure was also used for CO and THC (although not required by their respective EPA methods).

As shown in Figure 1, a $^1/_2$" diameter stainless steel probe was inserted into the sample port of the stack. The gas sample was continuously pulled through the probe and transported via $^3/_8$" heat-traced Teflon® tubing to the mobile laboratory through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into a heated sample manifold. From the heated manifold, the sample was partitioned to the hydrocarbon analyzer through heated lines. The bulk of the gas stream then passed to a stainless steel minimum contact condenser to dry the sample stream and into the (dry) sample manifold. From the manifold, the sample was partitioned to the analyzers through glass and stainless steel rotameters for flow control of the sample.

All instruments were housed in an air conditioned trailer-mounted mobile laboratory. Gaseous calibration standards were provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 was used to determine the cylinder concentrations where applicable (i.e., NO_X calibration gases).

EPA Method 1 procedures were used to determine the O_2-traverse point locations for sampling per the requirements of EPA Method 20. The location of the sample ports and the traverse point distances for the turbines are denoted by the stack diagrams located in Appendix A.

The stack gas analyses for CO_2 and O_2 concentrations were performed in accordance with procedures set forth in EPA Method 3a and Method 20, respectively. Instrumental analyses were used in lieu of an Orsat or a Fyrite procedure due to the greater accuracy and precision provided by the instruments. The CO_2 analyzer was based on the principle of infra-red absorption; the O_2 analyzer operated using a current generating micro-fuel cell.

The F_O calculation of EPA Method 3b (Section 3.4.1.1) was used to verify that the ratio of O_2 to CO_2 were within an acceptable range during the test runs. In all cases, the F_O fell within the expected values for fuel oil.

Opacity was determined via EPA Method 9. A one-hour opacity test run was performed on each unit by a visible emissions observer who was certified by Eastern Technical Associates of Raleigh, North Carolina. Appendix G provides both the opacity observation sheets as well as observer certification documentation.

CO emission concentrations were quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer was used for this purpose. This reference method analyzer was equipped with a gas correlation filter which removes most interference from moisture, CO_2, and other combustion products.

EPA Method 20 procedures were used to determine concentrations of NO_X (via chemiluminescence). NO_X mass emission rates were calculated as if all the NO_X was in the form of NO_2. This approach corresponds to EPA's convention, however, it tends to overestimate the actual NO_X mass emission rates since the majority of NO_X is in the form of NO which has less mass per unit volume (i.e., lbs. of emissions per ppmv concentration) than NO_2.

THC concentrations were quantified during the testing using Method 25a. These THC concentrations were used for determination of VOC; therefore, the methane fraction was included in these results. Total hydrocarbons were continuously measured throughout each test run using a flame ionization detector (FID). The THC continuous analyzer was calibrated on methane standards in an air matrix. Thus, the results included in this report are presented on a methane basis. Having the calibration standards in an air basis (i.e., 20.9% O_2) more closely matches the background matrix of the turbine exhaust and helps to reduce the effect of O_2 synergism on flame ionization detectors.

All data from the continuous monitoring instruments were recorded on two synchronized 3-pen strip chart recorders (Soltec Model 1243). These recorders were operated at a chart speed of 30 centimeters/hour and record over a 25-centimeter width. Strip chart records may be found in Appendix F of this report.

Fuel oil samples were shipped to Intertek Testing Services of Tampa, Florida. The samples were analyzed via ASTM D2622 to determine the total sulfur in the fuel. The reported SO_2 emission rates were calculated based on the results of the analyses and the turbine fuel flow measurements. The samples were analyzed via ASTM D4629 to determine the fuel bound nitrogen content. Since the results of the FBN analysis were below 150 ppm by weight, no correction to the allowable NO_X emissions was applicable. The fuel analysis results are in Appendix C of this report.

Particulate Matter Testing

EPA Method 1 was used to determine the PM traverse point locations. A cyclonic flow check was previously conducted on the turbines when fueled by natural gas. No significant cyclonic flow was encountered. The stack met the minimum criteria set forth in Paragraph 1.2 of that method. Pitot tube measurements were made at 6 separate traverse points in each of 4 sample ports, i.e., 12 sample points per stack cross section. The location of the sample ports and the pitot tube traverse point distances are denoted in the stack diagram, see Appendix A.

EPA Method 2 in conjunction with EPA Method 5 was used for determination of stack gas velocity during each run. An S-type pitot tube and inclined gauge oil manometer were used to measure the differential pressures at each traverse point. The stack gas temperature was determined with a K-type (chromel-alumel) thermocouple used in conjunction with a digital thermometer.

EPA Method 4 in conjunction with EPA Method 5 was used to measure the moisture content of the stack gases. A chilled liquid impingement system was used in conjunction with a calibrated dry gas meter to pull a sample greater than 30 standard cubic feet (scf). A K-type (chromel-alumel) thermocouple was used in conjunction with a digital thermometer to determine the last impinger temperatures in the chilled liquids impingement sampling train. This parameter is measured to ensure that the gas stream is cooled to a minimum of 68 degrees Fahrenheit as required by sampling methodology. Determination of the moisture content was necessary both to determine the stack gas molecular weight necessary for determination of volumetric flow (used for verification of sampling iso-kinetics) and to convert THC wet concentrations to VOC lbs/hr emissions. EPA Method 5 equations were used to calculate stack moisture content.

Particulate matter testing was conducted using the procedures of EPA Method 5. Figure 2 depicts the sampling system used for PM collection. A sample was continuously pulled through a heated probe and filter assembly (suspended on monorails) and then through an iced impinger train used to trap the stack moisture. The impinger train consisted of two impingers charged with distilled water, an empty impinger, and an impinger containing silica gel desiccant. The dry gas was then passed through a dry gas meter. A stainless steel nozzle and quartz probe liner was used for all PM testing. PM was collected onto a quartz fiber filter using a glass frit filter support and glass filter holder. Sampling iso-kinetics were maintained throughout each test run. The filter holder and probe were both maintained at a temperature of 248 °F ±25 °F as required by EPA Method 5. Each PM test run consisted of sampling for 60 minutes at six points from each of four ports for 2.5 minutes per point which allowed for the collection of at least 30 scf of sample during each test run. The field data sheets used to record the PM sampling data are available in Appendix A.

The PM filters were weighed before and after sampling. The weight gain of the filter plus the probe, nozzle, and front half of the filter holder (i.e., the "front half" of the sample train) rinse constituted to the PM emissions (as per EPA convention). All glass beaker boil-downs of the front half rinses and PM weighings were conducted at Cubix's Austin laboratory. The weighing data sheets are available in Appendix A.

All EPA Method 5 PM weighings were conducted on a Sartorius B120S balance. This balance has a 120 gram(g) capacity and a 0.0001 g sensitivity. The balance was leveled and zeroed before each series of weighings. All weighings of filters and beakers were repeated until a "constant weight" was obtained. A "constant weight" is defined by EPA Method 5 as a difference of no more than 0.5 mg or 1 percent of the total weight less tare weight, whichever is greater. This definition applies to two consecutive weighings with no less than 6 hours of desiccation time between weighings. The sample recovery data sheets in Appendix A describe the weighing times and dates and the difference between weighings is recorded to establish that a constant weight had been obtained.

The stoichiometric calculations of EPA Method 19 were used to calculate the stack volumetric flow rates and mass emission rates. These calculations are based on the heating value and the calculated O_2 and CO_2 "F-factors" (DSCF of exhaust per MMBtu of fuel burned) for fuel oil as based upon the fuel analysis for composition via ASTM D5291. Method 19 flow rate determinations are also based on the excess air (as measured from the exhaust diluent concentrations) and the fuel flow rates. EPA Method 19 was used as the stack flow rate measurement technique for all gaseous testing. Fuel samples were analyzed by the Intertek Testing Services, see Appendix C of this report. Appendix C also contains Cubix's fuel calculations for the O_2 and CO_2 "F-factors" and the gross heating value reported by the laboratory.

Cubix personnel collected ambient absolute pressure, temperature, and humidity data during each test run. A wet bulb/dry bulb sling psychrometer was used to determine ambient temperature and humidity conditions. An aircraft-type aneroid barometer (altimeter) was used to measure absolute atmospheric pressure.

All emission calculations were conducted by a computer spreadsheet as shown in Tables 2 through 6 of this report. Example calculations were performed manually using a hand-held calculator in order to verify the formulas used in the spreadsheet. Example calculations are located in Appendix B of this report.

TABLE 7
ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Common Use Ranges	Sensitivity	Response Time (sec.)	Detection Principle
NO_x	TECO Model 10 AR	0-10 ppm 0-100, 0-200 ppm 0-200, 0-500 ppm 0-1000, 0-2000 ppm 0-5000 ppm	0.1 ppm	1.7	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear within 1% of full scale.
CO	TECO Model 48	0-1, 0-10 ppm 0-20, 0-50 ppm 0-100, 0-200 ppm 0-500, 0-1000 ppm	0.1 ppm	60	Infrared absorption, gas filter correlation detector, microprocessor based linearization.
CO_2	Teledyne 731R	0-15%	0.03%	5.0	Non-dispersive infrared absorption, electronic linearization of a logarithmic signal (Beer's Law)
O_2	Teledyne 320 AR	0-5% 0-10% 0-25%	0.025% 0.05% 0.125%	15	Micro-fuel cell, inherently linear.
THC	JUM Model 3-300	0-10, 0-100, 0-1000, 0-10000 0-100,000 ppm	10 ppb	2.0	Flame ionization of hydrocarbons inherently linear within 1% over the range of the analyzer
PM	Mettler H6T Nutech 2010	0-160 grams 0-1 SCFM	0.0001 gram na	na na	Gravimetric analytical balance. Sample console with temperature controllers, sample pump, dry gas meter, orfice meter, and inclined manometer for isokinetic sampling

NOTE: Higher ranges available by sample dilution.
Other ranges available via signal attenuation.

FIGURE 1
INSTRUMENTAL SAMPLE SYSTEM DIAGRAM

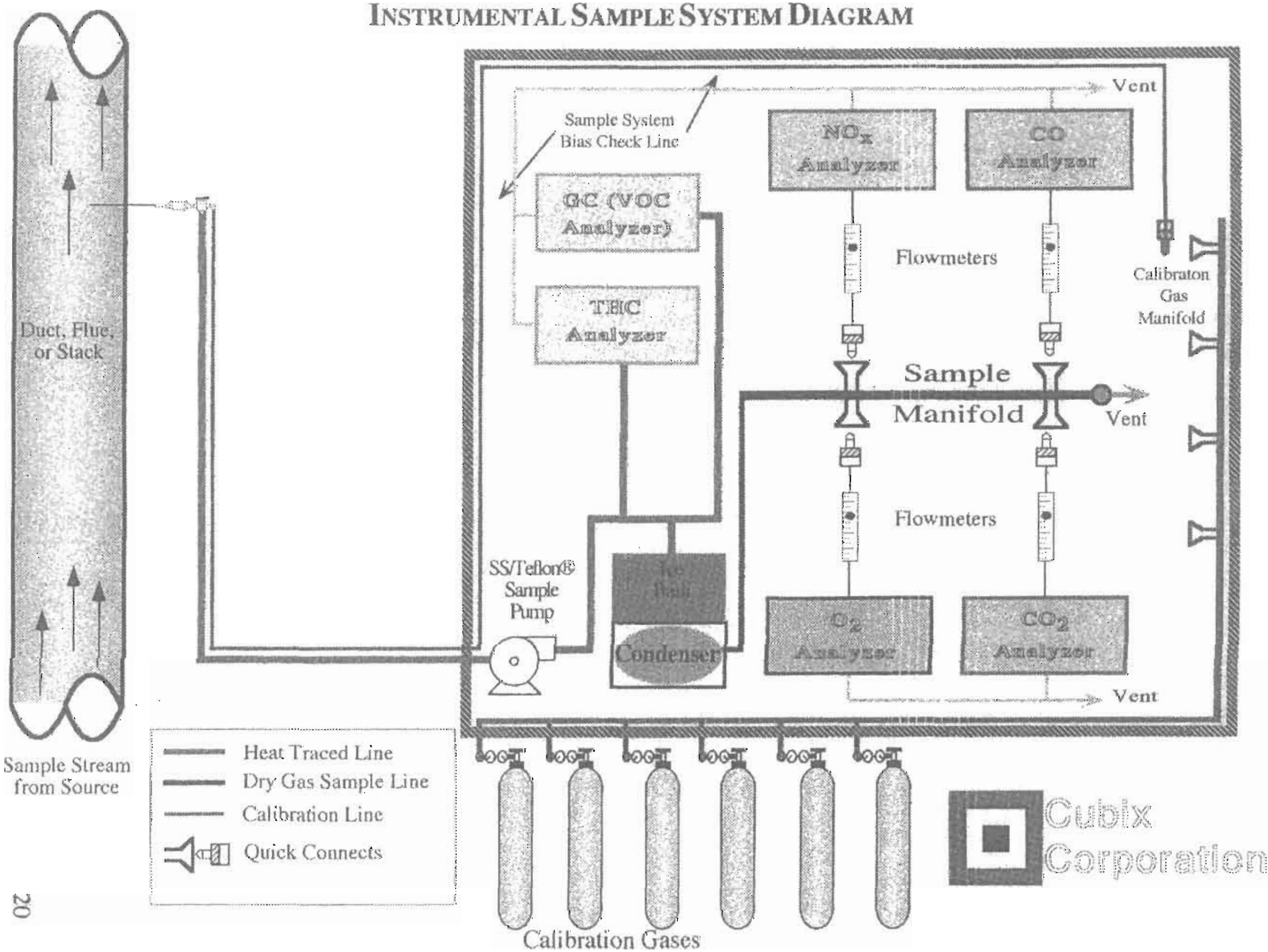
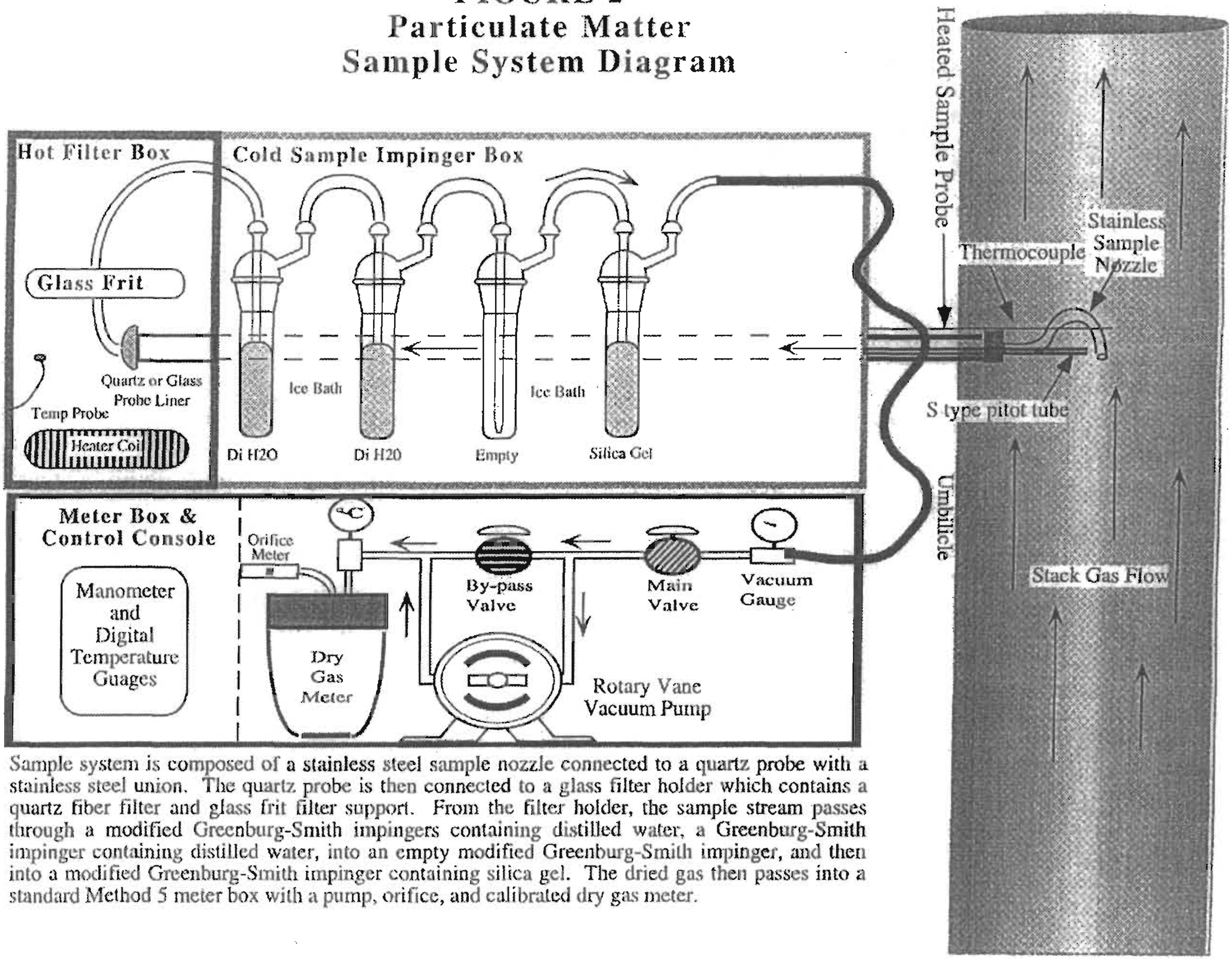


FIGURE 2
Particulate Matter
Sample System Diagram



Sample system is composed of a stainless steel sample nozzle connected to a quartz probe with a stainless steel union. The quartz probe is then connected to a glass filter holder which contains a quartz fiber filter and glass frit filter support. From the filter holder, the sample stream passes through a modified Greenburg-Smith impingers containing distilled water, a Greenburg-Smith impinger containing distilled water, into an empty modified Greenburg-Smith impinger, and then into a modified Greenburg-Smith impinger containing silica gel. The dried gas then passes into a standard Method 5 meter box with a pump, orifice, and calibrated dry gas meter.

QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities were undertaken before, during, and after this testing project. This section of the report combined with the documentation in Appendices D and E describe each of those activities.

Gaseous Emission Testing

A multi-point calibration was performed for each instrument in the field prior to the collection of data. The instrument's linearity was checked by first adjusting the instrument's zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response was then challenged with other calibration gases of known concentration. The instrument's response was accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range from the predicted values. (The responses of the infrared absorption type CO and CO_2 analyzers are electronically linearized.)

System bias checks were performed both before and after the sampling system was used for emissions testing. The sampling system's integrity was tested by comparing the responses of the NO_X analyzer to a calibration gas (and a zero gas) introduced via two paths as previously described in the *Analytical Techniques* section of this report. This system bias test was performed to assure that no alteration of the sample had occurred during the test due to leakage, reactions, or absorption. Similarly, system bias checks were performed with THC, CO, O_2, and CO_2 for added assurance of sample system integrity. The results of the system bias checks are available in Appendix D.

The efficiency of the NO_2 to NO converter in the NO_X analyzer was checked by having the analyzer sample a mixture of NO in N_2 standard gas and zero air from a Tedlar® bag. When this bag is mixed and exposed to sunlight, the NO is oxidized to NO_2. If the NO_X instrument's converter is 100% efficient, then the total NO_X response does not decrease as the NO in the bag is converted to NO_2. The criterion for acceptability is a decline of total NO_X concentration of less than 2% from the highest value over a 30 minute test period. The strip chart excerpts that demonstrate the converter efficiency test are available in Appendix F. The above mentioned quality assurance worksheet of Appendix E also summarizes the results of the converter efficiency test.

The residence time of the sampling and measurement system was estimated using the pump flow rate and the sampling system volume. The pump's rated flow rate is 0.8 scfm at 5 psig. The sampling system volume was approximately 0.32 scf. Therefore, the minimum sample residence time was ~ 24 seconds.

The NO_X and O_2 sampling and analysis system was checked for response time per the procedures outlined in EPA's Method 20, Section 5.5. The average NO_X analyzer's response times were 66.0 seconds upscale and 73.7 seconds downscale. The O_2 analyzer's average response times were 74.7 seconds upscale and 70.3 seconds downscale. The results of these response time tests are contained in Appendix E.

Interference response tests on the instruments were conducted by the instrument vendors and Cubix Corporation on the NO_X, CO, and O_2 analyzers. The sum of the interference responses for H_2O, C_3H_8, CO, CO_2 and O_2 is less than 2 percent of the applicable full scale span value. The instruments used for the tests meet the performance specifications for EPA Methods 3a, 7e, 10, and 20. The results of the interference tests are available in Appendix E of this report.

The sampling system was leak checked by demonstrating that it could hold a vacuum greater than 10 inches of mercury ("Hg) (>25 "Hg actual) for at least 1 minute with a decline of less than 1 "Hg. A leak test was conducted after the sample system was set up (i.e., before testing began) and before the system was dismantled (i.e., after testing was completed). This test was conducted to insure that ambient air was not diluting the sampling system. No leakage was detected.

As a minimum, before and after each test run, the analyzers were checked for zero and span drift. This allows test runs to be bracketed by calibrations and documents the precision of the data just collected. Calibration gases were introduced to the analyzers through the entire sampling system. Appendix E contains quality assurance tables which summarize the zero and span checks that were performed for each test run. The worksheets also contain the data used to correct the data for drift per EPA Method 6c, Equation 6c-1. NO_X, O_2, and CO_2 data were corrected for drift as required by the test methods. Although not required by the test methods, THC and CO concentrations were also corrected for drift to maintain consistency in results reporting.

The control gases used to calibrate the instruments were analyzed and certified by the compressed gas vendors to ±1% accuracy for all calibration gases. EPA Protocol No. 1 was used, where applicable (i.e., NO_X gases), to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM's). The gas calibration sheets as prepared by the vendor are contained in Appendix F.

Particulate Matter Testing

Quality assurance activities for the PM sampling began during preparation for the tests. All glassware was thoroughly washed, rinsed, dried, and packed safely to prevent contamination. American Chemical Society (ACS) reagent grade or better acetone was used for the washing of the sampling train. A blank of the acetone was treated in the same manner as the samples and retained for evaporation and weighing for contaminants. A blank filter was also weighed after treating it in the same manner as the filters used during sampling.

Prior to starting the PM/ testing, a preliminary velocity check was performed. This allowed for the calculation of the proper nozzle size and the "K" factor for isokinetic sampling.

The PM sampling system was leak checked by demonstrating that it could hold a vacuum greater than the highest sampling vacuum for at least 1 minute with a leakage rate less than 0.02 cubic feet per minute (cfm). A leak test was conducted after the sample system was set up (i.e., before each test run began at 15" Hg) and before the system was dismantled (i.e., after each test was completed). This leak check was performed in accordance with EPA Method 5 to ensure that the sample was not diluted by ambient air. No leaks greater than 0.02 cfm were detected.

All PM sampling was conducted iso-kinetically. Field checks of the iso-kinetics during each test run on each turbine were conducted to ensure strict adherence to EPA Method 5. Documentation of the iso-kinetics are available in Appendix A of this report.

After the post-test leak check of each run, the nozzle, probe, and front half of the filter holder were washed with acetone to remove adhering particulate matter. The front half washes were preserved for evaporation. Also, a blank of acetone was kept for analysis of residue. The quartz fiber filters were carefully removed from the filter holders after each test run and placed in containers and sealed against contamination.

The dry gas meter of the PM and moisture train was calibrated prior to testing in accordance with EPA Method 5. The dry gas meter in the Method 5 control box was calibrated, the orifice curve was generated and the pitot tubes tip were inspected. All glassware was thoroughly washed, rinsed, dried, and stored to prevent contamination. A calibration was also conducted on the dry gas meter at Cubix's Gainesville facility upon return from the project. A set of calibrated orifices were used for these calibrations. The calibration certifications of the particulate matter sampling system (dry gas meter, orifice curve and pitot tube calibrations) are found in Appendix E of this report. The meter showed a pre-test/post-test calibration factor difference of less than 5%.

Cubix collected and reported the enclosed test data in accordance with the procedures and quality assurance activities described in this test report. Cubix makes no warranty as to the suitability of the test methods. Cubix assumes no liability relating to the interpretation and use of the test data.

NSPS/BACT INITIAL COMPLIANCE and CO CEMS CERTIFICATION REPORT

for

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

December 2003

Prepared By:

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CERTIFICATION STATEMENT

Section IV, Appendix SC, Standard Condition No. 18-21. of Air Permit No. PSD-FL-296A 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

Robert J. Bivens
Staff Engineer II
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 2 – Units 2A and 2B) 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-296A, 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.

In addition, the Florida Department of Environmental Protection has required that the facility install, certify, and operate a CO continuous emissions monitoring system on both units.

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. The CO monitors installed on each unit were also successfully certified.

1.0 INTRODUCTION

Progress Energy's Hines Energy Complex – Power Block 2 (Hines PB2) has recently completed construction on two (2) combined-cycle turbine units (Units 2A and 2B) 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).

In addition, FL DEP has required that the facility install, certify, and operate a carbon monoxide (CO) continuous emissions monitoring system (CEMS) on both units.

The purpose of the test program was to determine compliance with specific air emission permit limits and CO monitoring requirements as contained in FL DEP Air Permit No. PSD-FL-296A. 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 Trigon Engineering Consultants, Inc. (Trigon). Regarding the CO CEMS, the cylinder gas audit (CGA) and 7-day calibration drift test were completed by Spectrum Systems personnel. 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 2A and 2B. Air Permit No. PSD-FL-296A, Section III, Condition No. 16 outlines the specific compliance testing requirements for Units 2A and 2B.

Condition No. 20.a of the above referenced permit outlines the CO CEMS certification testing requirements. Section 7.0 of this report details the results for CO CEMS testing portion of the test program.

Compliance testing for oxides of nitrogen (NO_x), oxygen (O_2), 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 2A and 2B, 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. Units 2A and 2B were also tested consecutively, and not simultaneously.

Note also that a NO_x CEMS certification was also performed concurrently on each unit along with the CO CEMS certification testing and compliance testing programs. The results of the NO_x CEMS certification testing 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 (i.e., RATA Runs 1-3 = Compliance Run 1, RATA Runs 4-6 = Compliance Run 2, RATA Runs 7-9 = Compliance Run 3). The RATAs were conducted while combusting natural gas only.

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 approved run times of each reference method (RM).

Table 2-1. Initial Compliance Test Matrix – Units 2A and 2B

Pollutant	Method	Fuel	Load Level	# of Runs	Duration	Permit Limit[1]
NO_x	7E	Gas	≥ 153 MW	9	21 min/run	3.5 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	12 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	9 ppm @ 15% O_2
CO	10	Gas	≥ 153 MW	9	21 min/run	16 ppm @ 15% O_2
		Oil	≥ 153 MW	3	60 min/run	30 ppm @ 15% O_2
VOC	25A	Gas	≥ 153 MW	3	60 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.

With the exception of the VE testing, all pollutants were concurrently sampled. Where necessary, the VE test runs were performed separately, due to the schedule availability of the VE reader, as well as limited daylight hours. In the event where the VE test runs were performed separately, those runs were performed under the same testing and load conditions as that of the pollutant test runs. In discussions with FL DEP during the test program, they were in agreement with this request.

Company: Florida Power Corporation
Plant: Hines Energy Complex
Location: near Ft. Meade in Polk County, Florida
Technicians: LJB, JFR, RPO, JAR
Source: Unit 1B, a Westinghouse 501F Power Turbine

TABLE 6: Summary of Results
Reduced Load Testing
Unit 1B

Test Number	Gas-BC-1	Gas-BC-2	Gas-BC-3	Gas-BC-4	Gas-BC-5	Gas-BC-6	Gas-BC-7	Gas-BC-8	Gas-BC-9
Date	12/29/98	12.29/98	12/29/98	12/29/98	12/29/98	12/29/98	12/29/98	12/29/98	12/29/98
Start Time	7:14	9:55	10:34	11:20	11:54	12:27	13:48	14:21	14:56
Stop Time	9:43	10:16	10:55	11:39	12:13	12:46	14:08	14:41	15:15
Turbine/Compressor Operation	Low Load, ~90 MW			Mid Load-1, ~110 MW			Mid Load-2, 130 MW		
Generator Output	89.99	89.96	90.14	110.11	109.94	109.94	130.02	130.14	129.87
Heat Input (higher heating value, HHV)	1067.8	1073.6	1073.6	1234.7	1245.1	1250.9	1408.4	1408.4	1408.4
Turbine Capacity (Mfg.'s Curve, heat input vs. inlet temp)	1,750	1,739	1,724	1,703	1,688	1,674	1,658	1,666	1,664
Percent Load (% of maximum heat input at inlet temp)	61.0	61.7	62.3	72.5	73.8	74.7	84.9	84.6	84.6
Engine Compressor Discharge Pressure (psia)	148.91	148.73	148.20	163.08	162.85	162.69	185.91	185.56	185.28
Turbine Air Inlet Temperature (°F)	60.91	63.31	66.70	71.40	74.53	77.37	80.44	79.00	79.25
Compressor Discharge Temperature Sel. (°F)	655	657	662	690	694	699	738	736	737
Mean Turbine Exhaust Temperature (°F)	1066	1070	1075	1089	1095	1101	1068	1069	1071
SCR Ammonia Injection Rate (lbs/hr)	83.79	86.26	105.28	88.73	125.46	114.16	74.27	62.56	77.62
Pre-SCR Temperature (SCR inlet temperature, °F)	573	578	579	584	565	574	599	600	600
Post-SCR Temperature (SCR outlet temperature, °F)	605	605	608	614	601	607	622	624	625
Turbine Fuel Data (Residue Gas)									
Fuel Heating Value (Btu/lb, HHV)	23122	23122	23122	23122	23122	23122	23122	23122	23122
Fuel Specific Gravity	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982	0.5982
Sulfur in Fuel (% weight, from ASTM D3246 analysis)	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060	0.00060
O_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	8646	8646	8646	8646	8646	8646	8646	8646	8646
CO_2 "F-factor" (DSCFex/MMBtu @ 0% excess air)	1034	1034	1034	1034	1034	1034	1034	1034	1034
Fuel Flow (KPPH)	46.18	46.43	46.43	53.40	53.85	54.10	60.91	60.91	60.91
Heat Input (MMBtu/hr, Higher Heat Value)	1067.8	1073.6	1073.6	1234.7	1245.1	1250.9	1408.4	1408.4	1408.4
Heat Input (MMBtu/hr, Lower Heat Value)	961.0	966.2	966.2	1111.2	1120.6	1125.8	1267.5	1267.5	1267.5
Ambient Conditions									
Atmospheric Pressure ("Hg)	29.60	29.60	29.59	29.58	29.56	29.53	29.51	29.50	29.48
Temperature (°F): Dry bulb	63.6	68.0	69.0	72.2	75.1	80.0	79.8	79.2	77.3
(°F): Wet bulb	63.6	67.0	68.0	69.2	70.8	73.3	75.5	76.1	76.4
Humidity (lbs moisture/lb of air)	0.0125	0.0138	0.0143	0.0145	0.0151	0.0159	0.0178	0.0185	0.0192
Measured Emissions									
NO_X (ppmv, dry basis)	14.19	15.73	10.67	15.58	16.82	13.60	7.67	11.17	10.63
O_2 (% volume, dry basis)	14.85	14.80	14.79	14.43	14.31	14.34	14.45	14.38	14.39
CO_2 (% volume, dry basis)	3.46	3.50	3.58	3.71	3.75	3.73	3.71	3.75	3.83
F_o (fuel factor, range = 1.600-1.836 for NG)	1.75	1.74	1.71	1.74	1.76	1.76	1.74	1.74	1.70
Stack Volumetric Flow Rates									
via O_2 "F_d-factor" (SCFH, dry basis)	3.19E+07	3.18E+07	3.18E+07	3.45E+07	3.41E+07	3.45E+07	3.95E+07	3.90E+07	3.91E+07
via CO_2 "F_c-factor" (SCFH, dry basis)	3.19E+07	3.17E+07	3.10E+07	3.44E+07	3.43E+07	3.47E+07	3.93E+07	3.88E+07	3.80E+07
Calculated Emission Rates (via M-19 O_2 "F-factor")									
NO_X (ppmv, dry @ 15% O_2)	13.8	15.2	10.3	14.2	15.1	12.2	7.0	10.1	9.6
NO_X (ppmv @ 15% O_2, ISO Day)	15.5	17.4	11.8	16.1	17.1	14.0	8.3	12.1	11.7
NO_X (lbs/hr)	**54.1**	**59.8**	**40.5**	**64.2**	**69.0**	**56.3**	**36.2**	**52.1**	**49.6**

PROCESS DESCRIPTION

Florida Power Corporation owns and operates the Hines Energy Complex in Polk County, Florida. Two recently installed combined cycle power generation units, manufactured by Siemens Westinghouse Power Corporation, each consist of a combustion turbine, a heat recovery steam generator, and a supplemental steam turbine. Emission testing was conducted on the units to determine their compliance status with state and federal regulations. This section of the test report provides a brief description of the units.

This facility is designated as Power Block 1, a two unit combined cycle power plant, Units 1A and 1B. The main body of each unit consists of a single shaft combustion turbine directly coupled to a 60 Hz generator. A heat recovery steam generator (HRSG) is installed just downstream of each turbine exhaust to recover additional energy (heat) from the process. The steam produced from the HRSGs may then drive steam turbines which generate additional electricity. The facility is designed to provide two fuels to the combustion turbines: No. 2 fuel oil or natural gas. During natural gas operation, NO_X emissions are controlled on each turbine with dry, low NO_X combustors and an ammonia injection SCR. While firing natural gas, each CT has a full load rating of approximately 165 MW in simple cycle mode and a heat input of 1757 MMBtu/hr, based upon the higher heat value, at site conditions of 59 °F inlet air temperature. FDEP has allowed the manufacturer's curve of heat input vs. turbine inlet temperature to define full load heat input for each CT (see Appendices H and J for curve data).

The circular CT/HRSG exhaust stacks were utilized for exhaust emission measurements of the turbine testing. The exhaust stack dimensions are depicted in the stack diagrams of Appendix A. Each stack is 130 feet tall and has a diameter of 216 inches. Four six-inch diameter sample ports are spaced perpendicular to each other. These ports are approximately 23 feet from the stack exit (107 feet above ground level). A service platform, a caged safety ladder, and a metal stairway were installed to provide access to the sample ports.

Operational data was obtained by FPC personnel from control panel instrumentation. Data was collected at 15 minute intervals (during the entire test period) and averaged over each test run period. The operational data reported in the summary tables is an average of the readings recorded during the gaseous test period of each run. All operational data sheets are located in Appendix H.

ANALYTICAL TECHNIQUES

Emissions from two combustion turbines were measured at the FPC Hines Energy Complex located in Polk County, Florida. These tests were performed by Cubix Corporation on December 29 and 31, 1998, and January 1 and 2, 1999, in order to determine the initial compliance status with regard to permitted emission limits while fueled with natural gas . This section of the report describes the analytical techniques and procedures used during these tests.

The sampling and analysis procedures used during these tests conformed with those outlined in The Code of Federal Regulations, 40 CFR 60, Appendix A, Methods 1, 2, 3a, 4, 5, 9, 10, 19, 20, 25a, and 26a (modified). The stack gas analyses for NO_X, CO, THC, O_2 and CO_2 were performed by continuous instrumental monitors. Exhaust gas analyses were performed on a dry basis for all compounds except THC. Table 7 lists the instruments and detection principles used for these analyses.

The test matrix for each turbine consisted of three sixty-minute (or greater) test runs at full load and three 18 minute and 40 second test runs at each of three reduced loads. Per EPA Method 20 requirements, an initial O_2-traverse was conducted and combined with the first low load test run. Forty-eight points in the stack cross section, twelve sample points in each of four ports, were measured for 140 seconds at each point. The sampling time at each point was determined from the sampling systems response time (see *Quality Assurance Activities).* No stratification of oxygen was found in either exhaust stack. Therefore, eight random points were sampled for 140 seconds each, 7.5 each for full load testing, in the subsequent test runs. reduced loads (~90 MW, ~110 MW, and ~135 MW), NO_X, CO_2, and O_2 stack gases were measured using continuous instrumental monitors. Stack gases were analyzed for NO_X, CO, THC, O_2, and CO_2 by continuous instrumental monitors during the full load test runs. All gas analyses were performed on a dry basis except hydrocarbons. Three 60 minute test runs were conducted at base load for all components except those components collected using a manual particulate matter and ammonia sampling train. The test runs for PM and NH_3 were extended to obtain a more representative sample due to low emission concentrations. A 60 minute VE test was conducted concurrently with one of the full load test runs on each unit.

Gaseous Emission Testing

Provisions were made to introduce the calibration gases to the instrumental monitors via two paths: 1) directly to the instruments via the sample manifold quick-connects and rotometers, and 2) through the complete sampling system including the sample probe, filter, heat trace, condenser, manifold, and rotometers. The former method was used for quick, convenient calibration checks. The latter method was used to demonstrate that the sample was not altered due to leakage, reactions, or adsorption within the sampling system (sample system bias check). A NO_X standard calibration gas was introduced into the NO_X analyzer directly. Then the response from the NO_X analyzer was noted as the calibration gas was introduced at the probe. Any difference between the two responses in the instrument was attributed to the bias of the sample system. Following the span gas bias check, a zero gas bias check was performed on the NO_X analyzer using nitrogen to check for any zero bias of the sample system. In accordance with EPA Method 3a this span and zero bias check procedure was repeated for the CO_2 and O_2 analyzers. This procedure was also used for CO and THC (although not required by their respective EPA methods).

As shown in Figure 1, a $^1/_2$" diameter stainless steel probe was inserted into the sample port of the stack. The gas sample was continuously pulled through the probe and transported via $^3/_8$" heat-traced Teflon® tubing to the mobile laboratory through Teflon® tubing via a stainless steel/Teflon® diaphragm pump and into a heated sample manifold. From the heated manifold, the sample was partitioned to the hydrocarbon analyzer through heated lines. The bulk of the gas stream then passed to a stainless steel minimum contact condenser to dry the sample stream and into the (dry) sample manifold. From the manifold, the sample was partitioned to the analyzers through glass and stainless steel rotometers for flow control of the sample.

All instruments were housed in an air conditioned trailer-mounted mobile laboratory. Gaseous calibration standards were provided in aluminum cylinders with the concentrations certified by the vendor. EPA Protocol No. 1 was used to determine the cylinder concentrations where applicable (i.e., NO_X calibration gases).

EPA Method 1 procedures were used to determine the O_2-traverse point locations for sampling per the requirements of EPA Method 20. The location of the sample ports and the traverse point distances for the turbines are denoted by the stack diagrams located in Appendix A.

The stack gas analyses for CO_2 and O_2 concentrations were performed in accordance with procedures set forth in EPA Method 3a and Method 20, respectively. Instrumental analyses were used in lieu of an Orsat or a Fyrite procedure due to the greater accuracy and precision provided by the instruments. The CO_2 analyzer was based on the principle of infra-red absorption; the O_2 analyzer operated using a current generating micro-fuel cell.

The F_O calculation of EPA Method 3b (Section 3.4.1.1) was used to verify that the ratio of O_2 to CO_2 were within an acceptable range during the test runs. In all cases, the F_O fell within the expected values for natural gas.

Opacity was determined via EPA Method 9. A one-hour opacity test run was performed on each unit by a visible emissions observer who was certified by Eastern Technical Associates of Raleigh, North Carolina. Appendix G provides both the opacity observation sheets as well as observer certification documentation.

CO emission concentrations were quantified in accordance with procedures set forth in EPA Method 10. A continuous nondispersive infrared (NDIR) analyzer was used for this purpose. This reference method analyzer was equipped with a gas correlation filter which removes most interference from moisture, CO_2, and other combustion products.

EPA Method 20 procedures were used to determine concentrations of NO_X (via chemiluminescence). NO_X mass emission rates were calculated as if all the NO_X was in the form of NO_2. This approach corresponds to EPA's convention, however, it tends to overestimate the actual NO_X mass emission rates since the majority of NO_X is in the form of NO which has less mass per unit volume (i.e., lbs. of emissions per ppmv concentration) than NO_2.

THC concentrations were quantified during the testing using Method 25a. These THC concentrations were used for determination of VOC; therefore, the methane fraction was included in these results. Total hydrocarbons were continuously measured throughout each test run using a flame ionization detector (FID). The THC continuous analyzer was calibrated on methane standards in an air matrix. Thus, the results included in this report are presented on a methane basis. Having the calibration standards in an air basis (i.e., 20.9% O_2) more closely matches the background matrix of the turbine exhaust and helps to reduce the effect of O_2 synergism on flame ionization detectors.

All data from the continuous monitoring instruments were recorded on two synchronized 3-pen strip chart recorders (Soltec Model 1243). These recorders were operated at a chart speed of 30 centimeters/hour and record over a 25-centimeter width. Strip chart records may be found in Appendix F of this report.

A natural gas fuel sample was analyzed on-line by the Florida Gas Transmission Perry Laboratory to determine the total sulfur in the fuel. The reported SO_2 emission rates were calculated based on the results of the analyses and the turbine fuel flow measurements. The fuel analysis results are in Appendix C of this report.

Particulate Matter and NH_3 Emission Testing

EPA Method 1 was used to determine the PM and traverse point locations. Prior to conducting the tests, a cyclonic flow check was conducted. No significant cyclonic flow was encountered. The stack met the minimum criteria set forth in Paragraph 1.2 of that method. Pitot tube measurements were made at 6 separate traverse points in each of 4 sample ports, i.e., 12 sample points per stack cross section. The location of the sample ports and the pitot tube traverse point distances are denoted in the stack diagram, see Appendix A.

EPA Method 2 in conjunction with EPA Method 5/26a was used for determination of stack gas velocity during each run. An S-type pitot tube and inclined gauge oil manometer were used to measure the differential pressures at each traverse point. The stack gas temperature was determined with a K-type (chromel-alumel) thermocouple used in conjunction with a digital thermometer.

EPA Method 4 in conjunction with EPA Method 5/26a was used to measure the moisture content of the stack gases. A chilled liquid impingement system was used in conjunction with a calibrated dry gas meter to pull a sample greater than 100 standard cubic feet (scf). A K-type (chromel-alumel) thermocouple was used in conjunction with a digital thermometer to determine the last impinger temperatures in the chilled liquids impingement sampling train. This parameter is measured to ensure that the gas stream is cooled to a minimum of 68 degrees Fahrenheit as required by sampling methodology. Determination of the moisture content was necessary both to determine the stack gas molecular weight necessary for determination of volumetric flow (used for verification of sampling iso-kinetics) and to convert THC wet concentrations to VOC lbs/hr emissions. EPA Method 5 equations were used to calculate stack moisture content.

Particulate matter testing was conducted using the procedures of EPA Method 5 in a combined EPA Method 5/Method 26a sample train. Figure 2 depicts the sampling system used for PM/NH_3 measurements. A sample was continuously pulled through a heated probe and filter assembly (suspended on monorails) and then through an iced impinger train with an aqueous acidic absorber solution to trap the ammonia and stack moisture. The dry gas was then passed through a dry gas meter. A glass nozzle and quartz probe liner was used for all PM/NH_3 testing. PM was collected onto a quartz fiber filter using a

Teflon® filter support and glass filter holder. Sampling iso-kinetics were maintained throughout each test run. Each PM test run consisted of sampling for approximately 2 to 3 hours at six points from each of four ports for which allowed for the collection of approximately 100 scf of sample during each test run. The field data sheets used to record the PM/NH_3 sampling data are available in Appendix A.

The PM filters were weighed before and after sampling. The weight gain of the filter plus the probe, nozzle, and front half of the filter holder (i.e., the "front half" of the sample train) rinse constituted to the PM emissions (as per EPA convention). All glass beaker boil-downs of the front half rinses and PM weighings were conducted at Cubix's Austin laboratory. The weighing data sheets are available in Appendix A.

All EPA Method 5 PM weighings were conducted on a Sartorius B120S balance. This balance has a 120 gram(g) capacity and a 0.0001 g sensitivity. The balance was leveled and zeroed before each series of weighings. All weighings of filters and beakers were repeated until a "constant weight" was obtained. A "constant weight" is defined by EPA Method 5 as a difference of no more than 0.5 mg or 1 percent of the total weight less tare weight, whichever is greater. This definition applies to two consecutive weighings with no less than 6 hours of desiccation time between weighings. The sample recovery data sheets in Appendix A describe the weighing times and dates and the difference between weighings is recorded to establish that a constant weight had been obtained.

During the PM tests firing on natural gas, an EPA Method 26a (modified) sample train was combined with the Method 5 train to allow for collection of NH_3 samples concurrently with the PM samples. This sample train was approved by FDEP, see Appendix J for correspondence. Figure 2 depicts the combined PM/NH_3 sample train.

EPA Method 26a calls for a filter followed by two impingers containing 0.1 N sulfuric acid (H_2SO_4) then followed by and two impingers containing 0.1 N sodium hydroxide (NaOH) and then a desiccant impinger. The H_2SO_4 impingers collect the basic NH_3 gases for analysis; and, the NaOH impingers are designed for collection and measurement of halogens such as chlorine and bromine. Since only NH_3 concentrations were of interest, Cubix omitted the NaOH impingers, the third and fourth impingers were empty and contained silica gel, respectively as called for in Method 5. The probe, nozzle, and PM filter holder rinse was not included in the NH_3 analysis. The filter holder and probe were both maintained at a temperature of 248 °F ±25 °F as required by both EPA Method 5 and 26a.

Cubix conducted the analyses of the ammonia samples on-site using the

Nessler Procedure. On-site analyses reduced the risk of sample losses common with sample transport and also afforded FPC the opportunity to take any corrective measures if the ammonia slip exceeded the permitted value. This analytical method consisted of reacting the ammonia sample with mercuric iodide to form a colorimetric complex. The absorbance of the colorimetric complex was then measured with a spectrophotometer at a wavelength of 405 nanometers (nm) and compared against a standard curve generated from a set of ammonium chloride standards.

Ammonia concentrations were also analyzed by ion chromatography (per the request of Martin Costello with FDEP) by Triangle Laboratories, Inc. of Durham, North Carolina. Sample were transferred to amber glass sample bottles after collection and kept chilled. These samples were then shipped with chain-of-custody forms to Triangle Labs in chilled sample coolers. Analysis was conducted in accordance with EPA Draft Method 206 using a Dionex DX300 ion chromatograph with a PED-II conductivity detector. A detailed description of the sample analysis and the results are contained in Appendix I.

The stoichiometric calculations of EPA Method 19 were used to calculate the stack volumetric flow rates and mass emission rates. These calculations are based on the heating value and the O_2 and CO_2 "F-factors" (DSCF of exhaust per MMBtu of fuel burned) for natural gas. Method 19 flow rate determinations are also based on the excess air (as measured from the exhaust diluent concentrations) and the fuel flow rates. EPA Method 19 was used as the stack flow rate measurement technique for all gaseous testing. A fuel sample was analyzed by the Florida Gas Transmission Perry Laboratory, see Appendix C of this report. Appendix C also contains Cubix's fuel calculations for the O_2 and CO_2 "F-factors" and the gross heating value reported by the laboratory.

Cubix personnel collected ambient absolute pressure, temperature, and humidity data during each test run. A wet bulb/dry bulb sling psychrometer was used to determine ambient temperature and humidity conditions. An aircraft-type aneroid barometer (altimeter) was used to measure absolute atmospheric pressure.

All emission calculations were conducted by a computer spreadsheet as shown in Tables 2 through 6 of this report. Example calculations were performed manually using a hand-held calculator in order to verify the formulas used in the spreadsheet. Example calculations are located in Appendix B of this report.

TABLE 7
ANALYTICAL INSTRUMENTATION

Parameter	Model and Manufacturer	Common Use Ranges	Sensitivity	Response Time (sec.)	Detection Principle
NO_X	TECO Model 10 AR	0-10 ppm 0-100, 0-200 ppm 0-200, 0-500 ppm 0-1000, 0-2000 ppm 0-5000 ppm	0.1 ppm	1.7	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear within 1% of full scale.
CO	TECO Model 48	0-1, 0-10 ppm 0-20, 0-50 ppm 0-100, 0-200 ppm 0-500, 0-1000 ppm	0.1 ppm	60	Infrared absorption, gas filter correlation detector, micro-processor based linearization.
CO_2	Teledyne 731R	0-15%	0.03%	5.0	Non-dispersive infrared absorption, electronic linearization of a logarithmic signal (Beer's Law)
O_2	Teledyne 320 AR	0-5% 0-10% 0-25%	0.025% 0.05% 0.125%	15	Micro-fuel cell, inherently linear.
THC	JUM Model 3-300	0-10, 0-100, 0-1000, 0-10000 0-100,000 ppm	10 ppb	2.0	Flame ionization of hydrocarbons inherently linear within 1% over the range of the analyzer
PM	Mettler H6T Nutech 2010	0-160 grams 0-1 SCFM	0.0001 gram na	na na	Analytical Balance Sample Console with temperature controllers, sample pump, dry gas meter, orfice meter, and inclined manometer for isokinetic sampling
NH_3	Bausch & Lomb Spec 20 (Spectrophotometer) (Nessler Procedure)	325-700 nm	2 nm	1-2	Optical Spectroscopy. Tungsten light source, photo-multiplier tube detection. Extended range filter.

NOTE: Higher ranges available by sample dilution.
Other ranges available via signal attenuation.

FIGURE 1
INSTRUMENTAL SAMPLE SYSTEM DIAGRAM

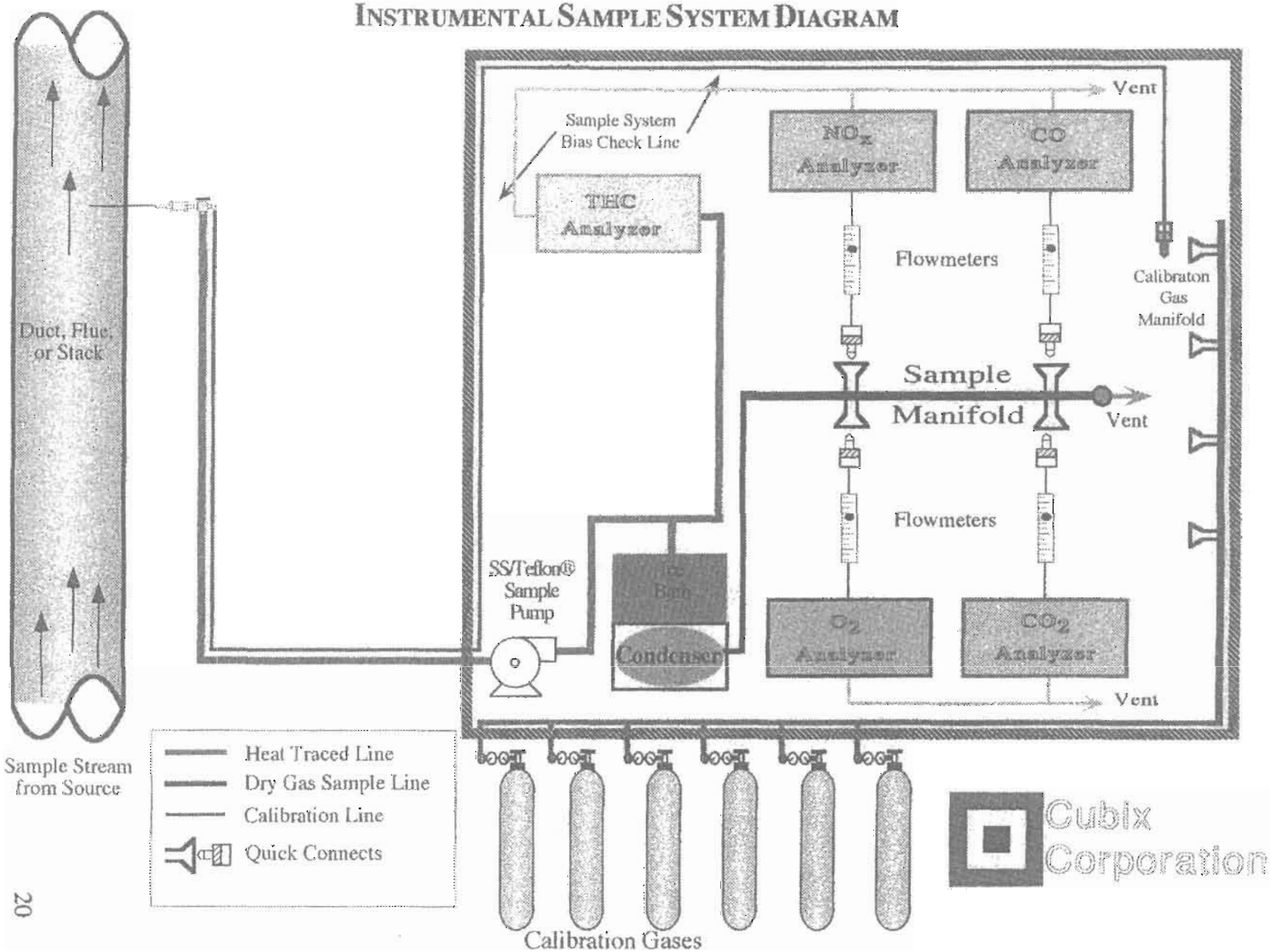
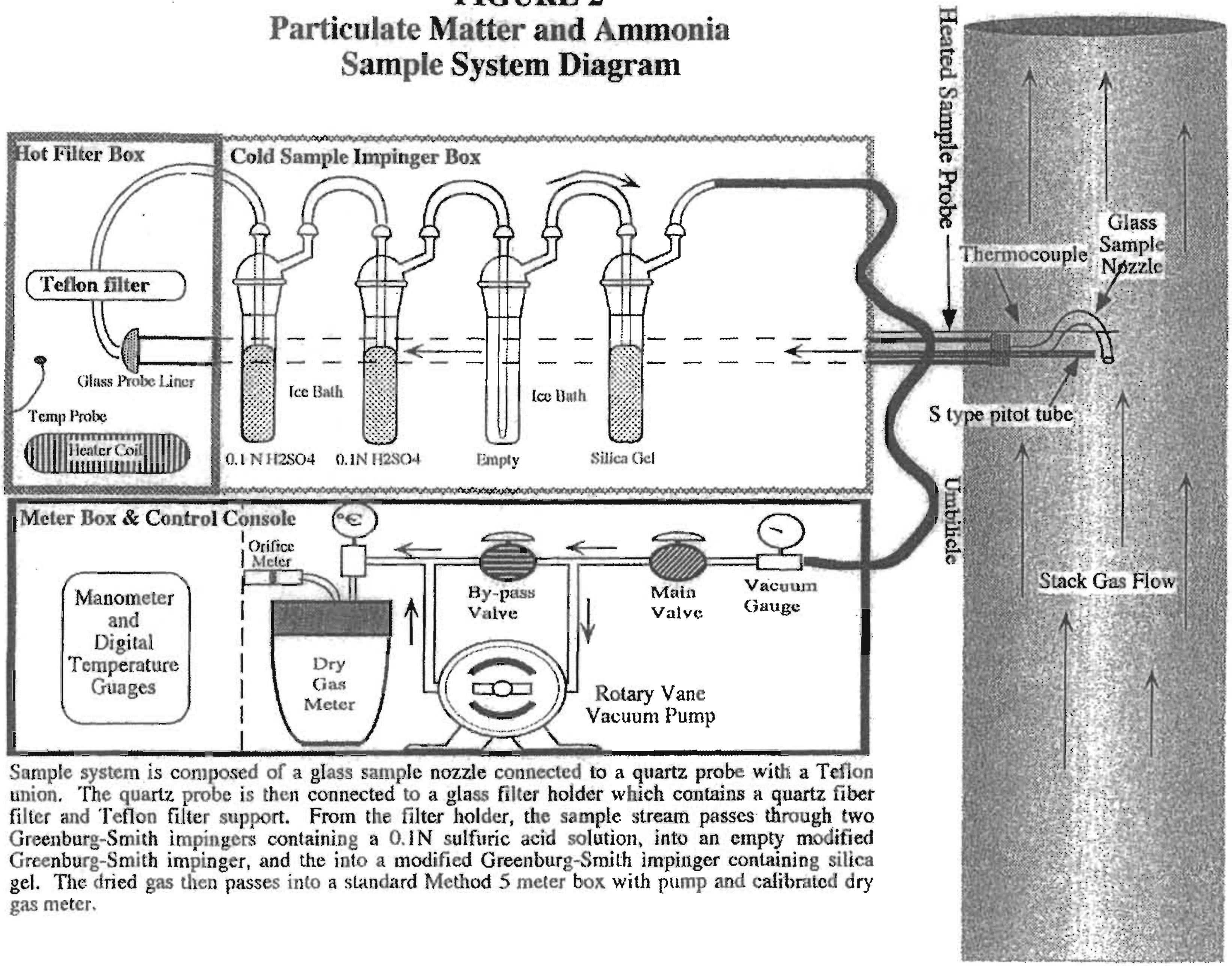


FIGURE 2
Particulate Matter and Ammonia Sample System Diagram



Sample system is composed of a glass sample nozzle connected to a quartz probe with a Teflon union. The quartz probe is then connected to a glass filter holder which contains a quartz fiber filter and Teflon filter support. From the filter holder, the sample stream passes through two Greenburg-Smith impingers containing a 0.1N sulfuric acid solution, into an empty modified Greenburg-Smith impinger, and the into a modified Greenburg-Smith impinger containing silica gel. The dried gas then passes into a standard Method 5 meter box with pump and calibrated dry gas meter.

QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities were undertaken before, during, and after this testing project. This section of the report combined with the documentation in Appendices D and E describe each of those activities.

Gaseous Emission Testing

A multi-point calibration was performed for each instrument in the field prior to the collection of data. The instrument's linearity was checked by first adjusting the instrument's zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response was then challenged with other calibration gases of known concentration. The instrument's response was accepted as being linear if the response of the other calibration gases agreed within ± 2 percent of range from the predicted values. (The responses of the infrared absorption type CO and CO_2 analyzers are electronically linearized.)

System bias checks were performed both before and after the sampling system was used for emissions testing. The sampling system's integrity was tested by comparing the responses of the NO_X analyzer to a calibration gas (and a zero gas) introduced via two paths as previously described in the *Analytical Techniques* section of this report. This system bias test was performed to assure that no alteration of the sample had occurred during the test due to leakage, reactions, or absorption. Similarly, system bias checks were performed with THC, CO, O_2, and CO_2 for added assurance of sample system integrity. The results of the system bias checks are available in Appendix D.

The efficiency of the NO_2 to NO converter (analyzer modified with a low temperature molybdenum NO_2 to NO converter to prevent measuring NH_3 as NO_X) in the NO_X analyzer was checked by having the analyzer sample a mixture of NO in N_2 standard gas and zero air from a Tedlar® bag. When this bag is mixed and exposed to sunlight, the NO is oxidized to NO_2. If the NO_X instrument's converter is 100% efficient, then the total NO_X response does not decrease as the NO in the bag is converted to NO_2. The criterion for acceptability is a decline of total NO_X concentration of less than 2% from the highest value over a 30 minute test period. The strip chart excerpts that demonstrate the converter efficiency test are available in Appendix F. The above mentioned quality assurance worksheet of Appendix E also summarizes the results of the converter efficiency test.

The residence time of the sampling and measurement system was estimated using the pump flow rate and the sampling system volume. The pump's rated flow rate is 0.8 scfm at 5 psig. The sampling system volume was approximately 0.32 scf. Therefore, the minimum sample residence time was ~ 24 seconds.

The NO_X and O_2 sampling and analysis system was checked for response time per the procedures outlined in EPA's Method 20, Section 5.5. The average NO_X analyzer's response times were 66.0 seconds upscale and 73.7 seconds downscale. The O_2 analyzer's average response times were 74.7 seconds upscale and 70.3 seconds downscale. The results of these response time tests are contained in Appendix E.

Interference response tests on the instruments were conducted by the instrument vendors and Cubix Corporation on the NO_X, CO, and O_2 analyzers. The sum of the interference responses for H_2O, C_3H_8, CO, CO_2 and O_2 is less than 2 percent of the applicable full scale span value. The instruments used for the tests meet the performance specifications for EPA Methods 3a, 7e, 10, and 20. The results of the interference tests are available in Appendix E of this report.

The sampling system was leak checked by demonstrating that it could hold a vacuum greater than 10 inches of mercury ("Hg) (>25 "Hg actual) for at least 1 minute with a decline of less than 1 "Hg. A leak test was conducted after the sample system was set up (i.e., before testing began) and before the system was dismantled (i.e., after testing was completed). This test was conducted to insure that ambient air was not diluting the sampling system. No leakage was detected.

As a minimum, before and after each test run, the analyzers were checked for zero and span drift. This allows test runs to be bracketed by calibrations and documents the precision of the data just collected. Calibration gases were introduced to the analyzers through the entire sampling system. Appendix E contains quality assurance tables which summarize the zero and span checks that were performed for each test run. The worksheets also contain the data used to correct the data for drift per EPA Method 6c, Equation 6c-1. NO_X, O_2, and CO_2 data were corrected for drift as required by the test methods. Although not required by the test methods, THC and CO concentrations were also corrected for drift to maintain consistency in results reporting.

The control gases used to calibrate the instruments were analyzed and certified by the compressed gas vendors to ±1% accuracy for all calibration gases. EPA Protocol No. 1 was used, where applicable (i.e., NO_X gases), to assign the concentration values traceable to the National Institute of Standards and

Technology (NIST), Standard Reference Materials (SRM's). The gas calibration sheets as prepared by the vendor are contained in Appendix F.

Particulate Matter and NH_3 Emission Testing

Quality assurance activities for the PM/NH_3 sampling began during preparation for the tests. All glassware was thoroughly washed, rinsed, dried, and packed safely to prevent contamination. American Chemical Society (ACS) reagent grade or better acetone was used for the washing of the sampling train. ACS reagent grade or better NH_3 absorber and analysis reagents were also selected. A blank of the acetone was treated in the same manner as the samples and retained for evaporation and weighing for contaminants. A blank filter was also weighed after treating it in the same manner as the filters used during sampling.

Prior to starting the PM/NH_3 testing, preliminary velocity, and cyclonic flow checks were performed. This allowed for the calculation of the proper nozzle size and the "K" factor for isokinetic sampling.

The PM sampling system was leak checked by demonstrating that it could hold a vacuum greater than the highest sampling vacuum for at least 1 minute with a leakage rate less than 0.02 cubic feet per minute (cfm). A leak test was conducted after the sample system was set up (i.e., before each test run began at 15" Hg) and before the system was dismantled (i.e., after each test was completed). This leak check was performed in accordance with EPA Method 5 to ensure that the sample was not diluted by ambient air. No leaks greater than 0.02 cfm were detected.

All PM sampling was conducted iso-kinetically. Field checks of the iso-kinetics during each test run on each turbine were conducted to ensure strict adherence to EPA Method 5. Documentation of the iso-kinetics are available in Appendix A of this report.

After the post-test leak check of each run, the nozzle, probe, and front half of the filter holder were washed with acetone to remove adhering particulate matter. The front half washes were preserved for evaporation. Also, a blank of acetone was kept for analysis of residue. The quartz fiber filters were carefully removed from the filter holders after each test run and placed in containers and sealed against contamination.

After each NH_3 test run, the impingers of absorber solution and required sections of connecting glassware were rinsed and stored in glass amber sample bottles. Each sample was rinsed with a specified volume of 0.1 N H_2SO_4. Sample bottles were labeled, sealed and stored in a chilled ice chest following on-site ammonia analysis. They were then shipped with a chain-of-custody form to Triangle Laboratories, Inc.

Nessler procedure ammonia analyses were conducted daily. Multi-point calibrations and sample blanks were performed on a daily basis each time ammonia samples were analyzed. In addition, a sample duplicate and spike analysis was conducted with analysis of Test Run Gas-BC-10. The sample duplicate was within 5% relative standard deviation of the sample results; the sample spike recovery was within 100% ±10% of the expected results. Collection efficiencies for the sampling system were determined for each test run, see Appendix A. The collection efficiency was greater than 90% for all full load compliance test runs.

Ion chromatographic analyses of the NH_3 samples were conducted in duplicate with the inclusion of a sample spike and sample blank. All duplicates and sample blanks fell within the requirements of the analytical method. Discussion of the quality assurance activities is in the lab reports in Appendix I. Collection efficiency between the first impinger and the second from the NH_3 samples for the test runs was within the method requirements of 90% efficiency.

The dry gas meter of the PM/NH_3 and moisture train was calibrated prior to testing in accordance with EPA Method 5. The dry gas meter in the Method 5 control box was calibrated, the orifice curve was generated and the pitot tubes tip were inspected. All glassware was thoroughly washed, rinsed, dried, and stored to prevent contamination. A calibration was also conducted on the dry gas meter at Cubix's Gainesville facility upon return from the project. A set of calibrated orifices were used for these calibrations. The calibration certifications of the particulate matter sampling system (dry gas meter, orifice curve and pitot tube calibrations) are found in Appendix E of this report. The meter showed a pre-test/post-test calibration factor difference of less than 5%.

Cubix collected and reported the enclosed test data in accordance with the procedures and quality assurance activities described in this test report. Cubix makes no warranty as to the suitability of the test methods. Cubix assumes no liability relating to the interpretation and use of the test data.

ATTACHMENT 3

HINES ENERGY CENTER EMISSION TEST DATA

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 2A 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?
163.1	1824.7	194.8	NO_x ppm	2.98	**3.5**	**Yes**
			CO ppm	0.74	**16**	**Yes**
			VOC ppm	0.47	**2**	**Yes**
			NH_3 ppm	3.73	**5**	**Yes**
			VE %	0	**10**	**Yes**

[1]Heat input based upon a gross calorific (GCV) value of 1,036 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.

Table 3-2. Summary of Initial Compliance Testing Results – Unit 2B 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?
166.7	1832.6	190.8	NO_x ppm	3.20	**3.5**	**Yes**
			CO ppm	0.76	**16**	**Yes**
			VOC ppm	0.80	**2**	**Yes**
			NH_3 ppm	2.92	**5**	**Yes**
			VE %	0	**10**	**Yes**

[1]Heat input based upon a GCV value of 1,036 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.

Table 3-3. Summary of Initial Compliance Testing Results – Unit 2A 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?
158.3	1653.7	431.0	NO_x ppm	8.88	12	Yes
			CO ppm	0.99	30	Yes
			VOC ppm	0.29	10	Yes
			NH_3 ppm	2.52	9	Yes
			VE %	0	10	Yes

[1]Heat input based upon a GCV value of 19,093 Btu/lb and a density of 6.69 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.

Table 3-4. Summary of Initial Compliance Testing Results – Unit 2B 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?
161.3	1659.9	552.3	NO_x ppm	10.51	12	Yes
			CO ppm	0.63	30	Yes
			VOC ppm	0.03	10	Yes
			NH_3 ppm	2.23	9	Yes
			VE %	0	10	Yes

[1]Heat input based upon a GCV value of 19,093 Btu/lb and a density of 6.69 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.

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 % of the maximum achievable load (and subsequent, resultant heat input levels) for each respective day and test condition.

4.0 FACILITY DESCRIPTION

4.1 Facility Location

Progress Energy's Hines Energy Complex is located at County Road 555, Bartow, Polk County, Florida. For the PB2 project, Progress Energy is currently permitted to construct and operate (2) combustion turbine (CT) units (Units 2A and 2B), which are used for electricity generation and sale.

4.2 Unit Descriptions

Units 2A and 2B are Siemens Westinghouse 501 FD CTs with a maximum rated electrical output of ~170 MW each. Units 2A and 2B share a common steam turbine, rated at ~190 MW, for a total combined-cycle unit (CCU) system output of approximately 530 MW.

Units 2A and 2B are dual-fuel fired units that combust natural gas as a primary fuel and No. 2 fuel oil as an "off-season" back-up fuel. The maximum heat input rating (based upon the higher heating value of the fuel, and an ambient temperature of 59 °F) of each unit while firing natural gas is 1,915 mmBtu/hr. The maximum heat input rating rating (based upon the higher heating value of the fuel, and an ambient temperature of 59 °F) of each unit while firing No. 2 fuel oil is 2,020 mmBtu/hr.

For the control of NO_x emissions, each unit uses dry low-NO_x burners (DLNBs) and ammonia injection while firing natural gas. Each unit uses water and ammonia injection while firing No. 2 fuel oil. Each unit has its own HRSG used for combined-cycle operation; however, neither of the units use duct burners for supplementary heat input. Appendix 2 of this report contains the combined process flow diagram for Units 2A and 2B.

4.3 Reference Methods Sampling Locations

The stack testing locations (as well as other pertinent, descriptive information) for each unit's outlet stack are described in Table 4-1. Appendix 2 contains the engineering stack diagrams and dimensions for Units 2A and 2B. All stack dimensions were verified for completeness and accuracy at the time of testing.

Table 4-1. Stack Testing Locations – Units 2A and 2B

Unit	Stack Exit Height (feet)	Test Platform Height (feet)	Stack ID (feet)	Accessed By?
2A	125	~110	19.06	Stairs + Ladder
2B	125	~110	19.06	Stairs + Ladder

5.0 REFERENCE METHOD COMPLIANCE TESTING PROCEDURES

This section includes a brief discussion of the test methods that were used for sampling and analysis at the Hines Energy Complex facility. Unless stated otherwise, all stack sampling was performed in accordance with the applicable test methods as prescribed in the referenced air permit. Any deviations from the standard procedures were previously noted in the test protocol (see Appendix 10 of this report) that was previously submitted and approved.

During the compliance test program, all process data was electronically logged and printed out by the plant control room's data acquisition and handling system (DAHS). All process data taken during this test program is provided in Appendix 4 of this report.

While firing natural gas, all 60-minute ammonia and VOC test runs were performed during the respective "3 x 21-minute" RATA runs for NO_x and CO. The process data taken during the RATA runs was also used as the process data for a given 60-minute block of ammonia and VOC test run data, since those data values remained steady-state and constant.

5.1 Sample and Velocity Traverse (RM 1)

Velocity measurements were not required as part of this test program. Hence, RM 1, used for the determination of the number and location of sample points used for a given velocity or isokinetic traverse, was not applicable or relevant to this test program. Additionally, the verification of the absence of cyclonic flow was not necessitated.

It was proposed, however, that for all ammonia sampling (both fuels), a 3-point sample traverse be performed. These 3 points were proposed to be located at 0.4, 1.2, and 2.0 meters (i.e., 15.8, 47.2, and 78.7 inches) from the stack wall. Please reference Section 5.6 of this report for more detailed information concerning the selection of these particular traverse points.

For the NO_x, CO, and O_2 sampling, a 3-point traverse was also utilized when the RATA testing was performed. Please reference Section 7.1.4.1 of this report for more detailed information concerning the selection of these particular traverse points. For the VOC testing, and for the NO_x, CO, and O_2 sampling while firing No. 2 fuel oil, a single-point traverse was used.

5.2 Instrumental Reference Methods – NO_x (RM 7E), CO (RM 10), and O_2 (RM 3A)

Source emission testing was performed on both units to demonstrate compliance with the NO_x limits specified in the referenced air permit. RM 7E was used for the NO_x testing. For the NO_x sampling, a set of nine 21-minute test runs was performed at high (i.e., normal) load on both units while combusting natural gas. A set of three 1-hour test runs was performed at high load on both units while combusting No. 2 fuel oil.

Testing was also performed to verify compliance with the CO limits as specified in the air permit. RM 10 was used to determine CO emissions. For the CO sampling, a set of nine 21-minute test runs was performed at high (i.e., normal) load on both units while combusting natural gas. A set of three 1-hour test runs was performed at high load on both units while combusting No. 2 fuel oil.

O_2 concentrations were concurrently determined using the procedures described in RM 3A. The O_2 values were obtained in order to calculate values of NO_x and CO ppm corrected to 15% O_2, as well as VOC and NH_3 ppm corrected to 15% O_2. Since molecular weight values were not required for any part of this test program, CO_2 measurements were not necessitated. O_2 values were, however, obtained during all of the pollutant test runs performed throughout the test program.

For the NO_x, CO, and O_2 measurements, the sample was extracted from the stack effluent through a heated sample probe and heated sample line to a sample conditioner where moisture was removed. The dried gas sample was then pumped to a distribution manifold where a portion of the sample gas was distributed to each analyzer. Since the possible presence of ammonia in the RM sample may bias any RM NO_x measurements high, a permeation tube ammonia scrubber was installed on the RM NO_x analyzer immediately upstream of the sample inlet to the analyzer, in order to eliminate any possible ammonia interference.

In accordance with RM 3A and 7E, a three-point (i.e., zero-, mid- and high-level) calibration error check (i.e., direct analyzer calibration) was conducted on the O_2 and NO_x analyzers at the beginning of each test day, or when deemed necessary at the tester's discretion (e.g., switching units or gases, lengthy downtime, suspected drift, etc.). For RM 3A and 7E, the mid-level calibration gas is required to be 40-60% of span, while the high-level calibration gas is required to be 80-100% of span. This check was conducted by sequentially injecting the zero and span calibration gases directly into the analyzer, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the direct calibration, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (either nitrogen or cross-zero gas) and the span adjustment using only one of the two span gases. Acceptable system performance checks dictate that the difference between the analyzer responses and the respective cylinder tag values will not exceed ≥ 2% of span.

Zero and upscale system calibration checks (i.e., system bias calibration) were performed both before and after each test run in order to quantify reference measurement sampling system bias and calibration drift. In instances when the test runs immediately follow one another, the post-cal for the run immediately preceding a subsequent run was also be the pre-cal for that forthcoming run. Upscale was considered either the mid- or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the in-stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System bias and drift were then assessed. Sampling system bias is defined as the difference between the test run calibration check responses (system bias calibration) and the initial calibration error responses (direct analyzer calibration) as a percentage of span. Drift is defined as the difference between the pre- and post-test run system bias calibration responses.

If an acceptable post-test bias check result was obtained but the zero or upscale drift result exceeded the drift limit, the test run was considered valid; however, the direct analyzer calibration and system bias check procedures were repeated before conducting the next test run. A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded the bias specification. Again, the direct analyzer calibration and system bias check procedures must be repeated before conducting the next test run. Acceptable system performance checks dictate that system bias calibration checks will not exceed ≥ 5% of span or, for drift checks, ≥ 3% of span.

An NO to NO_2 converter efficiency test was successfully performed on the RM NO_x analyzer both before and after the test program as described in §5.6.1 of RM 20. The results of these tests are contained in Appendix 9 of this report. Note, however, that as a guideline and per §4.1.4 of RM 20, an NO_2 to NO converter is not necessary if the CT is operated at 90% or more of peak load capacity, which was the case during the NO_x sampling for this test program.

Concentrations of CO were also extracted continuously from the stack via the same sample transport system as that used for the O_2 and NO_x sampling. The calibration techniques for CO are similar to that for O_2 and NO_x, with the following exceptions: For CO, a four-point (i.e., zero-, low-, mid- and high-level) calibration error check (i.e., direct analyzer calibration) was conducted on the CO analyzer at the beginning of each test day, or when deemed necessary at the tester's discretion. For RM 10, the low-level calibration gas is required to be ~30% of span, the mid-level calibration gas ~60% of span, and the high-level gas is typically ~90-100% of span. For all system bias calibration checks, upscale was considered either the low-, mid-, or high-level gas, or whichever gas most closely approximated the flue gas level. The calibration performance specifications for CO were the same as that for the NO_x and O_2 measurements.

During this test program, in no instance did a direct calibration, system bias calibration, or drift comparison exceed the specifications as prescribed by the applicable test methods for O_2, NO_x, or CO. The actual calibrations, as well as the quality assurance checks of these calibrations, can be found in Appendix 3 of this report.

5.3 Instrumental Reference Methods – VOCs (RM 25A)

Testing for VOC concentrations was performed using RM 25A. A set of three 1-hour test runs were performed on each unit while firing each fuel independently.

For the VOC measurements, a single-point sample was extracted from the stack effluent through a heated sample probe and heated sample line and transported to a hydrocarbon FID analyzer. The VOC sample was quantified as a hot/wet value (i.e., moisture was not removed), and was transported through a separate sample system from the NO_x/CO/O_2 sample. All raw VOC data was calibrated and quantified as propane (C_3H_8). Under those circumstances, the raw VOC data values was multiplied by a correction factor of three (3) in order to convert the VOC concentrations from an "as propane" basis to an "as carbon" basis.

Prior to the test series, the heated sample line was heated to ~250°F and the hydrocarbon analyzer was heated above 300°F to prevent condensation. After the temperatures had stabilized, the hydrocarbon analyzer was ignited using a 100% ultra high purity (UHP) hydrogen fuel and hydrocarbon free air. The analyzer was then calibrated.

In accordance with RM 25A, a four-point (i.e., zero-, low-, mid- and high-level) calibration error check (i.e., a system tuning check) was conducted on the VOC analyzer at the beginning of each test day, or when deemed necessary at the tester's discretion. For RM 25A, the low-level calibration gas is required to be 25-35% of span, the mid-level calibration gas is required to be 45-55% of span, and the high-level calibration gas is required to be 80-90% of span. Unlike the direct calibration error check employed by RM 3A, 7E, and 10, RM 25A uses a system tuning check by shooting calibration gas throughout the entire sampling system, rather than immediately from the calibration gas cylinder(s) to the analyzer. This check was conducted by sequentially injecting the zero and span calibration gases throughout the sampling system, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the system tuning check, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (either nitrogen or cross-zero gas) and the span adjustment using the high-level calibration gas. Based upon the zero- and high-level responses, the predicted response for the low- and mid-level gases were then calculated. Acceptable performance specifications for the system tuning checks dictate that the difference between the analyzer responses (either tuned [high] or predicted [low/mid]) and the respective cylinder tag values will not exceed ≥ 5% of the respective calibration gas tag value. For the zero gas, a performance specification of < 3% of <u>span</u> was used, since any % of the <u>tag value</u> for zero gas is 0.00 ppm.

Zero and upscale system calibration checks (i.e., system bias calibrations) were performed both before and after each test run in order to quantify reference measurement calibration drift. In instances when the test runs immediately followed one another, the post-cal for the run immediately preceding a subsequent run was also be the pre-cal for that forthcoming run. Upscale was considered either the low-, mid-, or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the in-stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System drift was then assessed. (Note that RM 25A does not assess system bias, nor does it correct any raw values for system bias). Drift is defined as the difference between the pre- and post-test run calibration responses.

A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded a drift specification of ≥ 3% of span. Note that RM 25A does not clearly specify whether drift is defined as a pre- versus post-run comparison, or a post-run versus initial tuning calibration (of the day) comparison. For this test program, the drift comparisons were made under each of the two scenarios.

During this test program, in no instance did a system tuning check, system bias calibration, or drift comparison exceed the specifications as prescribed by RM 25A or the submitted test protocol. The actual calibrations, as well as the quality assurance checks of these calibrations, can be found in Appendix 3 of this report.

Note that, for this test program, it was not necessary to "subtract out" any methane concentrations, since the raw VOC values measured were well below the permitted limits for all fuel and load conditions.

5.4 Instrumental Reference Method Calibration Gases and Equipment

Since RM 3A, 7E, 10, and 25A are instantaneous, "real time" test methods, NO_x, CO, and VOC compliance (ppm @ 15% O_2) was determined at the time of the initial compliance test.

The reference calibration gases used during this test program were certified following EPA Protocol analysis procedures. No calibration gas cylinders were used that contained less than 200 psi of gas, nor were any cylinders expired. Copies of the calibration gas "certificates of analysis" are provided in Appendix 9 of this report. RMB personnel have cross-checked and verified that the certification sheets provided in this test report match those cylinders/respective calibration gas concentrations used in the field during this test program.

Tables 5-1 and 5-2 summarize the analyzer spans and calibration gas values used for the RM measurements during the compliance testing for Units 2A and 2B. The spans used were based upon either a suitably accurate operating range for a particular monitor, or on concentrations exhibited by identical sources in prior test programs.

Table 5-1. RM Analyzer Spans and Calibration Gas Values – Natural Gas

		Calibration Gas Values (% of span)			
Analyzer	Span	Zero-Level	Low	Mid (40–60%)	High (80–100%)
NO_x	0–10 ppm	Nitrogen or CZG[1]	Not Required	4.93 ppm	9.70 ppm
O_2	0–25%	Nitrogen or CZG[1]	Not Required	12.5 %	20.9 %
		Zero-Level	Low (~30%)[2]	Mid (~60%)[2]	High (~90–100%)
CO	0–30 ppm	Nitrogen or CZG[1]	9.26 ppm	18.1 ppm	28.1 ppm
		Zero-Level	Low (25–35%)	Mid (45–55%)	High (80–90%)
VOC (C_3H_8)[3]	0–10 ppm	Nitrogen or CZG[1]	3.21 ppm	5.01 ppm	7.93 ppm

[1]CZG = Cross-Zero Gas (e.g., for NO_x, perform the zero-level calibration using either nitrogen, O_2, CO, or C_3H_8).
[2]A calibration gas tolerance band of ± 5% of the span required by RM 10 was used to increase calibration gas availability/possibilities.
[3]All RM 25A calibrations were quantified as propane.

Table 5-2. RM Analyzer Spans and Calibration Gas Values – No. 2 Fuel Oil

		Calibration Gas Values (% of span)			
Analyzer	Span	Zero-Level	Low	Mid (40–60%)	High (80–100%)
NO_x	0–20 ppm	Nitrogen or CZG[1]	Not Required	9.70 ppm	16.3 ppm
O_2	0–25%	Nitrogen or CZG[1]	Not Required	12.5 %	20.9 %
		Zero-Level	Low (~30%)[2]	Mid (~60%)[2]	High (~90–100%)
CO	0–30 ppm	Nitrogen or CZG[1]	9.26 ppm	18.1 ppm	28.1 ppm
		Zero-Level	Low (25–35%)	Mid (45–55%)	High (80–90%)
VOC (C_3H_8)[3]	0–10 ppm	Nitrogen or CZG[1]	3.21 ppm	5.01 ppm	7.93 ppm

[1]CZG = Cross-Zero Gas (e.g., for NO_x, perform the zero-level calibration using either nitrogen, O_2, CO, or C_3H_8).
[2]A calibration gas tolerance band of ± 5% of the span required by RM 10 was used to increase calibration gas availability/possibilities.
[3]All RM 25A calibrations were quantified as propane.

Table 5-3 summarizes the RM analyzer manufacturer, model, and principle of operation for each analyzer used during the test program. All of the RM analyzers used were those that are typical of the RMs used during this test program.

Table 5-3. RM Analyzer Descriptions

Method	Analyzer	Manufacturer	Model	Principle of Operation
7E	NO_x	API	200 AH	Chemiluminescence
3A	O_2	California Analytical	200	Fuel Cell
10	CO	API	300	Gas Filter Correlation
25A	VOC	J.U.M.	VE-7	Flame Ionization

5.5 Instrumental Reference Method Calculations

The RM analyzer measurements were recorded as 1-, 21-, and 60-minute averages on the test team's DAHS, where applicable. All test run concentration results were determined from the average gas concentrations measured during the run. For NO_x, CO, and O_2, the raw data values were adjusted for bias based upon the zero and upscale sampling system bias calibration results (per Equation 6C-1 presented in RM 6C, §8). These bias adjusted values were also "automatically" provided by the test team's STRATA DAS software. Even though the STRATA software provided "bias corrected values" for the VOC concentrations, those values were not used. Rather, all of the raw, uncorrected VOC data was used for the compliance determination.

The NO_x, CO, and VOC ppm values corrected to 15% O_2 were calculated as follows:

$$C_{15} = C * \frac{5.9}{20.9 - \%O_2}$$

Where: C_{15} = Average pollutant concentration corrected to 15% O_2, expressed as ppm dry
C = Average pollutant concentration during respective compliance test run, expressed as ppm dry
O_2 = Average oxygen content during respective compliance test run, expressed as % dry

Note that, based upon the concurrently performed ammonia/moisture sampling (see Section 5.6 of this report), all VOC ppmw values were converted to ppmd, for the purposes of calculating VOC ppmd corrected to 15% O_2. The ppmw to ppmd conversion was performed as follows:

$$ppmd = \frac{ppmw}{1 - B_{ws}}$$

Where: ppmd = Average VOC concentration converted to ppm dry
ppmw = Average VOC concentration during respective compliance test run, measured as ppm wet
B_{ws}= Moisture content of stack gas, expressed as a decimal (e.g., 12% H_2O = 0.12 B_{ws})

Note also that any calculations corrected to ISO standard conditions are no longer appropriate for NSPS Subpart GG units, since those calculations are outdated. EPA has issued guidance in the past to this effect (i.e., Applicability Determination No. 0000063), and this guidance has previously been provided to and accepted by FL DEP and the utility industry. However, Hines PB2 will maintain records of ambient temperature, ambient humidity, and combustor inlet pressure as required by Section IV – Appendix GG of the above referenced air permit, in the event that EPA or FL DEP requests this information in the future.

5.6 Ammonia Slip Testing (CTM–027)

As part of this test program, ammonia slip testing was also performed on Units 2A and 2B using procedures based upon Conditional Test Method 027 (CTM–027). A set of three 1-hour test runs were performed on each unit while firing each fuel independently. All ammonia slip testing was performed concurrently with the compliance testing for the other pollutants. All ammonia injection rates during testing were at the normal rates anticipated to be used during subsequent, everyday, unit operation.

For this test program, the following modifications to CTM–027 were previously proposed to and approved by FL DEP. These modifications were intended to make the test program easier to perform without compromising the integrity or accuracy of the test results:

- Samples were not collected isokinetically. It is understood that CTM-027 includes the isokinetic sampling procedure as it was originally intended (and validated) to collect particulate matter in conjunction with ammonia from a coal-fired boiler.

- It was proposed to use a Method 4-type sampling arrangement with a heated (at stack temperature) glass-lined probe. An open-ended probe with a glass wool plug was used in lieu of an in-stack filter and nozzle, since there is negligible particulate in these sources, and since CTM-027 does not require filter recovery or analysis. The probe was connected in series with an impinger train set up per CTM-027. The sample was sampled non-isokinetically at the constant $\Delta H_{@}$ rate of the meter box, which is typically ~0.75 cfm. For 1-hour runs, a minimum of approximately forty-two (42) dry standard cubic feet (dscf) would be collected for each test run.

- A single-port, three (3) point traverse of 0.4, 1.2, and 2.0 meters (i.e., 15.8, 47.2, and 78.7 inches) from the stack wall was used. This 3-point traverse was used to acquire a more representative stack sample, and was consistent with the "short" 3-point traverse used to perform RATAs under 40 CFR Part 75 and 40 CFR Part 60.

For this test program, the following CTM–027 procedures continued to be followed:

- The sample trains consisted of four (4) impingers. Impingers 1 and 2 each contained 100 ml of 0.1 N sulfuric acid (H_2SO_4). Impinger 3 was empty. Impinger 4 contained 200-300 g of indicating silica gel. Impingers 1 and 2 both contained Greenburg-Smith tips, while Impingers 3 and 4 were modified to not have tips, as required by CTM-027.

- All sample recoveries (e.g., probe and impinger rinses), transport, and analyses were performed according to the procedures specified by CTM-027. The sample recovery began by removing the glass wool from the probe inlet. The probe liner assembly was then rinsed with deionized (DI) water to remove any particulate, then rinsed with acetone to dry the glassware. The ammonia sample recovery began by measuring the liquid in the first three impingers to the nearest milliliter. The moisture collected by the silica gel in the fourth impinger was determined to the nearest 0.1 gram. The collected condensate measurements were then recorded on the Method 4 moisture determination data analysis form (as provided in Appendix 5 of this report). The impinger contents and rinses from the impingers and the connecting glassware were transferred to the appropriate, individual storage containers as required by the method. The samples, along with the proper chain of custody documentation, were then forwarded to the analytical laboratory. Ammonia concentrations were determined by ion chromatography equipped with a conductivity detector. The 0.1N sulfuric acid impinger blank and DI rinse blanks were also prepared according to the RM criteria.

This Method-4 type sampling arrangement was proposed since only the values of (a) dscf of sample volume and (b) the ammonia catch weight (μg) are required to calculate and quantify ammonia ppm (which was the only parameter needed for this test program). To quantify the dscf values, only the parameters of (1) actual sample volume, (2) meter box gamma, (3) meter box temperature, (4) barometric pressure, and (5) $\Delta H_{@}$ are needed. Using a Method-4 sampling arrangement provides all of these parameters. Isokinetic sampling, on the other hand, introduces several potential sources of sampling error, yet would yield essentially the same results as that of this proposed, modified approach.

All ammonia analyses were performed by Enthalpy Analytical, Inc. (Enthalpy). The Enthalpy test results are contained in Appendix 6 of this report. Appendix 6 also contains the gas chromatograms used to derive those results.

For clarification, the following equation was used in order to quantify ammonia ppm. This equation was provided by Enthalpy:

$$C_{NH3} = \frac{\mu g / MW}{\left(V_{m(std)} * 28.316\right) / GC}$$

where: C_{NH3} = ammonia concentration (ppm)
μg = micrograms of ammonia collected in sample run
MW = molecular weight of ammonia (17 lb/lb-mol)
$V_{m(std)}$ = volume of sample taken during test run (dscf)
28.316 = factor to convert from dscf to L of sample (1 ft^3 = 28.316 L) [note that the method requires that the sample volume be converted from dscf to L prior to calculating ppm]
GC = molar gas constant (24.056)

The moisture content of the gas stream was also determined simultaneously during the CTM-027 runs. The flue gas moisture content was needed to be quantified in order to convert all VOC ppmw values to ppmd.

5.7 Visible Emissions Testing (RM 9)

As part of this test program, VE readings were taken by a certified VE reader using RM 9. One thirty (30) minute test run was performed on Unit 2A and Unit 2B while combusting natural gas and No. 2 fuel oil at high load. VE readings were taken at 15-second intervals, or 120 readings per run. 6-minute block averages were calculated in order to determine compliance with the permit limit, which requires that the stack "opacity" be no more than 10 % per 6-minute block. The VE field data and VE reader certification are contained in Appendix 8 of this report.

6.0 MISCELLANEOUS PERMIT REQUIREMENTS

6.1 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

The referenced air permit also includes emission "limitations" for sulfur dioxide (SO_2) and sulfuric acid mist (SAM). However, the concentrations of these pollutants were not required to be determined as part of the compliance test program. Rather, the referenced air permit provides alternate means and/or methods for determining these concentrations.

The fuels used on the units have sulfur limitations that effectively limit the potential emissions of SO_2 and SAM from the gas turbines and represent the BACT determination for these pollutants. Compliance with the fuel specifications (and subsequently and SO_2 and SAM limits) shall be demonstrated by keeping records of the sulfur contents of the fuels.

These records are currently maintained on site. Note that the natural gas documentation (total sulfur grains and GCV) that the facility maintains is also required under 40 CFR Part 75, Appendix D. Also note that the most recent sulfur analysis for the No. 2 fuel oil (% sulfur, GCV, and density) was submitted to FL DEP under separate cover on October 9, 2003.

6.2 Turbine Performance Curves

Specific Condition No. 7 of Air Permit No. PSD-FL-296A also requires that "manufacturer performance curves" be submitted within the same time frame after testing as the compliance test report. These performance curves depict power output versus heat input at three different turbine inlet [i.e., ambient] operating temperatures, for the purpose of making site specific corrections for heat input and power output. The curves are provided in Appendix 4 of this report.

Note that these curves are completely theoretical in nature only, and can differ based upon any actual, real-world plant data that is accumulated during the forthcoming operating histories of the units.

7.0 CO CEMS CERTIFICATION PROCEDURES AND RESULTS

Hines PB2 has also installed and certified a CO monitor on each of the two affected units to comply with the monitoring, recordkeeping and reporting requirements of the 40 CFR Part 60 rules.

The purpose of this certification test program was to satisfy the 40 CFR Part 60, Appendices B and F requirements as required by FL DEP for initially certifying the CO monitor. The CO monitors that were installed and certified on each unit are straight-extractive CO monitors, which are ultimately used to measure and record CO ppm @ 15% O_2. The CO monitors were certified in accordance with the procedures established in 40 CFR Part 60, Appendix B, PS-4A.

Table 7-1 provides the analyzer span, manufacturer, and model information of the CO monitors installed and certified on Units 2A and 2B.

Table 7-1. CO Monitor Information – Units 2A and 2B

Unit	Span	Manufacturer	Model	Serial No.
2A	0–50/1,200 ppm	Thermo Environmental Instruments, Inc.	48C	73426-373
2B	0–50/1,200 ppm	Thermo Environmental Instruments, Inc.	48C	73424-373

In accordance with 40 CFR Part 60, Appendices B and F, Hines PB2 was required to perform the following quality assurance checks in order to certify each monitor –

- Cylinder Gas Audit (CGA),
- Seven (7) day calibration drift test,
- Response time test, and
- A minimum nine (9) run RATA

<u>*NOTE*</u>

A NO_x CEMS (i.e., NO_x + O_2 analyzer) was also installed and certified on Hines PB2 Units 2A and 2B. Per the FL DEP air permit requirement referenced above, the NO_x analyzer is to be certified pursuant to 40 CFR Part 75. Based upon the most recent air permit revision, the O_2

analyzer shall be certified pursuant to 40 CFR Part 75, but shall be the same diluent analyzer used to quantify both NO_x (under 40 CFR Part 75) and CO (under 40 CFR Part 60) concentrations corrected to 15% O_2. A 40 CFR Part 75, Appendix D NO_x CEMS certification application report has been submitted to FL DEP and US EPA Region IV, as part of the Hines PB2 Acid Rain Program monitoring plan, under separate cover on or about the same time as this compliance and CO CEMS test report. The NO_x CEMS certification application report also contains the applicable fuel flowmeter and facility DAHS information.

7.1 CO CEMS CERTIFICATION TESTS

Hines PB2 successfully completed each of the required certification tests for the Unit 2A and 2B CO monitors as of **November 13, 2003**. The CGA and 7-day calibration drift tests were completed by Spectrum Systems personnel. The response time test was completed by RMB Consulting & Research, Inc. personnel. The RATA was conducted by Trigon Engineering Consultants, Inc. Contact information for this certification program can be found in Appendix 10 of this report.

7.1.1 Cylinder Gas Audit

For each of the two monitors, a CGA was performed on both ranges of the dual range CO in accordance with the procedures in 40 CFR Part 60, Appendix F, §5.1.2. The CGAs were performed using EPA Protocol calibration gases corresponding to 20-30% and 50-60% of the analyzer span, while the unit(s) were operating. 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 monitor (%)
C_m = Average of the monitoring system responses
C_a = Cylinder tag value

The CGA results are acceptable if the monitor accuracy 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 7-2 provides a summary of the CGA test results, and Appendix 7 of this report contains the complete CGA test results.

Table 7-2. Summary of CGA Test Results

Unit	Test Date	Test Parameter	Reference Value	Average Response	Percent Error	Performance Specification
2A	09/10/03	CO (H) – high	Not Required			
		CO (H) – mid	670.0	668.0	0.3	≤ 15% of tag value
		CO (H) – low	300.2	300.5	0.1	≤ 15% of tag value
	09/10/03	CO (L) – high	Not Required			
		CO (L) – mid	27.04	26.93	0.4	≤ 15% of tag value
		CO (L) – low	12.93	12.83	0.8	≤ 15% of tag value
2B	09/03/03	CO (H) – high	Not Required			
		CO (H) – mid	674.0	675.0	0.1	≤ 15% of tag value
		CO (H) – low	304.3	305.9	0.5	≤ 15% of tag value
	09/03/03	CO (L) – high	Not Required			
		CO (L) – mid	28.02	28.17	0.5	≤ 15% of tag value
		CO (L) – low	12.89	13.07	1.4	≤ 15% of tag value

7.1.2 Seven (7) Day Calibration Drift Test

Calibration drift tests were performed on both ranges of each dual-range CO analyzer 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-4A, §13.1. Each analyzer range was challenged with two EPA Protocol gas concentrations corresponding to 0.0-20.0% and 50.0-60.0% of span. Calibration drift is determined by the following equation:

$$CD = \left|\frac{C - M}{S}\right| \times 100$$

Where: CD= Percentage calibration drift based upon instrument span
C = Reference value of zero- or upscale-level calibration gas introduced into the monitor
M = Actual monitoring system response to the calibration gas
S = Span of the instrument

Table 7-3 provides a summary of the 7-day calibration drift results for the CO analyzers. Detailed results of the 7-day calibration drift tests are presented in Appendix 7 of this report. The maximum drift specification for the CO analyzer is 5 % of the instrument's span for six out of seven test days.

Table 7-3. Summary of 7-Day Calibration Drift Test Results

Unit	Test Dates	Test Parameter	Zero-Level[1]	Span-Level[2]	Performance Specification
2A	09/12/03 – 09/18/03	CO (H)	0.6 ppm	22.2 ppm	≤ ± 60 ppm
		CO (L)	0.8 ppm	1.1 ppm	≤ ± 2.5 ppm
2B	09/04/03 – 09/10/03	CO (H)	1.1 ppm	20.5 ppm	≤ ± 60 ppm
		CO (L)	0.8 ppm	0.3 ppm	≤ ± 2.5 ppm

[1]Highest zero-level calibration drift shown during 7-day calibration error test period.
[2]Highest span-level calibration drift shown during 7-day calibration error test period.

7.1.3 Response Time Test

During the monitor certification, a response time test was performed on the low and high range of the CO analyzer of each unit according to the procedures outlined in 40 CFR Part 60, Appendix B, PS-4A, §8.3.

In order to perform the response time test, zero gas was introduced into the CO analyzer. When the CO analyzer output stabilized (i.e., no change greater than 1% of full scale for 30 seconds), an upscale CO calibration gas was then 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 introduced 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 were determined. The slower (i.e., longer) of the four means (i.e., an upscale and downscale mean for the low and high analyzer range) was deemed the CO monitor response time. The CO monitor response time shall not exceed 1.5 minutes (i.e., 90 seconds) to achieve 95% of the final stable value.

Table 7-4 provides a summary of the response time results for Units 2A and 2B. The supporting test data are provided in Appendix 7 of this report.

Table 7-4. Summary of Response Time Test Results

Unit	Analyzer	Response Time		Performance Specification
		Upscale	Downscale	
2A	CO (H)	80 seconds	**83 seconds**	≤ 90 seconds
	CO (L)	60 seconds	60 seconds	
2B	CO (H)	66 seconds	**83 seconds**	≤ 90 seconds
	CO (L)	56 seconds	60 seconds	

NOTE: Response times in **bold** (i.e., the slowest/longest time) indicate the response time of the CO monitor.

7.1.4 Relative Accuracy Test Audit Procedures

A RATA was performed on each of the two CO monitors by Trigon Engineering Consultants, Inc. in accordance with 40 CFR Part 60, Appendix B, PS-4A, §§8.1 and 13.2. Each RATA consisted of nine (9) 21-minute comparative test runs. The RM test team used EPA Method 10 to make the CO measurements, respectively. A stratification test was also performed at each unit's test location prior to performing the RATA. Table 7-5 provides a summary of the RATA results. The tertiary performance specification, which allows for the relative accuracy (RA) to be calculated as the absolute difference between the RM and CEMS to be within ± 5 ppm CO (plus the confidence coefficient), was used for this test program.

Table 7-5. Summary of CO RATA Results

Unit	Date	Load (MW)	RATA Result		Performance Specification		
			@ stack O_2	@ 15% O_2	Primary	Secondary	Tertiary
2A	11/08/03	163	0.86 ppm	0.72 ppm	RA ≤ 10%[2]	RA ≤ 5%[3]	**≤ ± 5 ppm**
2B	11/07/03	167	0.53 ppm	0.46 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.

7.1.4.1 Stratification Testing and Traverse Point Selection

During each RATA test run, a three (3) point traverse was performed. Consistent with 40 CFR Part 60, Appendix B, Performance Specification 2, §8.1.3.2, a stratification test was performed on each stack prior to commencing the RATA testing. For the stratification tests, a twelve (12) point traverse was performed using the sampling points determined via 40 CFR Part 60, Appendix A, RM 1. Each point was sampled for one (1) minute plus system response time.

The 40 CFR Part 60 regulations state that if the mean average of the entire traverse is more than 10% different from any single point, then it is presumed that stratification exists within the stack. If the cross-section of the stack is found to be stratified, then the three traverse points should be located along a single "long" measurement line at 16.7, 50.0, and 83.7 percent of the stack inside diameter (i.e., 38.2, 114.4, and 191.4 inches). If the cross-section of the stack is not found to be stratified, then the three traverse points shall be located along a single "short" measurement line at 0.4, 1.2, and 2.0 meters (i.e., 15.8, 47.2, and 78.7 inches) from the stack wall.

However, in the interests of trying to avoid the use of a 16-18 foot sample probe, the "short" measurement line was used, provided that the "short" measurement line provided a representative sample over the cross section of the stack. For this test program, it was proposed (and approved by FL DEP) that a "representative sample" was achieved if the average of the three sample points on the "short" measurement line was within 10% of the average of the entire 12-point stratification traverse. The "short" measurement line would also be consistent with the 40 CFR Part 75 traverse, which was performed concurrently at the time of the 40 CFR Part 60 RATA.

Table 7-6 summarizes the stratification test results for Units 2A and 2B. Based upon the results, the "short" measurement line was used for the subsequent RATA testing.

Table 7-6. Stratification Test Results

Unit	Average CO (12 pt. traverse)	Average CO (3 pt. traverse)	Allowable CO Range	Within Range?
2A	0.71 ppm	0.64 ppm	0.64–0.78 ppm	Yes
2B	0.76 ppm	0.71 ppm	0.68–0.83 ppm	Yes

7.1.4.2 Relative Accuracy Test Audit

Consistent with the annual RATA requirements specified in PS-4A of 40 CFR Part 60, Appendix B, PS-4A, §§ 8.1 and 13.2, the RA of a minimum nine-run performance test for CO must be ≤ 10% when the average RM value is used to calculate RA, ≤ 5% when the applicable emission standard (i.e., CO ppm @ 15% O_2) is used to calculate RA, or within ± 5 ppm when the RA is calculated as the absolute average difference between the RM and CEMS plus the 2.5 percent confidence coefficient. Any of the above three options may be chosen, depending upon the test team's and plant's discretion. For this particular RATA, the ± 5 ppm CO criteria was used.

Note that the RATA test was performed while the CO analyzer is operating in its "low" range (i.e., 0–50 ppm).

A minimum of nine (9) runs must be performed for any given RATA. As an option, more than nine runs may be performed in order to achieve a desired RATA result. If this option is chosen, a maximum of up to three (3) runs may be excluded from the final relative accuracy calculation(s), as long as the total number of test runs used to determine the relative accuracy or bias is greater than or equal to nine. If more than nine runs are performed, the data for all the individual runs shall be included in the final CEMS certification report, even if the results of those individual test runs are not used in the final relative accuracy calculation. For the RATAs performed on Units 2A and 2B, only nine (9) total runs were necessitated and performed on each unit. Table 7-7 provides a summary of the RATA test run calculation and reporting requirements as outlined in 40 CFR Part 60, Appendix B, PS-2, §8.4.4.

Table 7-7. 40 CFR Part 60 RATA Test Run Calculation and Reporting Requirements

NUMBER OF RATA TEST RUNS (N) –			
Performed	Used In Calculations	Excluded From Calculations	Reported
9 *(minimum)*	9	0	9
10	9	1	10
11	9	2	11
12	9	3 *(maximum)*	12
N ≥ 13	N–3	3 *(maximum)*	N

Measurements of CO concentrations (ppmd) were made according to EPA RM 10 of 40 CFR Part 60, Appendix A and then compared to the CO measurements made by the source CEMS. All CO measurements were made simultaneously. All pre-test and on-site field checks of the RM CEMS, as well as all measurements made throughout the testing, were conducted according to the procedures specified in the applicable EPA methods, as well as the applicable quality assurance procedures detailed in EPA's Quality Assurance Handbook for Air Pollution Measurement Systems: Volume III – Stationary Source-Specific Methods (EPA/600/R-94/038c).

A single-load RATA for each unit was conducted while the subject unit was operating at > 50% of normal load, per 40 CFR Part 60, Appendix B, PS-2, §8.4.1. The RATAs were conducted while the units were combusting natural gas. Nine (9) 21-minute comparative RATA runs were performed. During each 21-minute sample run, a three-point traverse was conducted. In order to appropriately calculate and report the CO RATA data, the following process data was provided by the plant: (1) date, (2) time, (3) unit, (4) load, (5) fuel, and (6) CO ppm.

Note again that the RATA and compliance testing (while firing natural gas) were performed simultaneously. Reference Sections 5.2 and 5.4 of this report for further information concerning the test methodology, calibration procedures, sample calculations, and calibration gas values.

Appendix 7 of this report contains the tabular run-by-run results of the CO RATAs performed on these units.

7.1.4.3 Bias Adjustment Factor (BAF)

Bias adjustment factors do not apply to any analyzer certified under 40 CFR Part 60.

8.0 Fuel Flowmeters and Heat Input Calculations

Natural gas fuel flow is measured using a dedicated orifice-plate type fuel flowmeter for each unit. No. 2 fuel oil flow is measured using a turbine meter for each unit.

The Hines PB2 facility quantifies fuel flow for natural gas in thousand standard cubic feet per hour (kscfh), and No. 2 fuel oil in gallons per minute (GPM). The following equations are used in order to convert these units to heat input (mmBtu/hr), for each respective fuel:

Natural gas

$$HI_g = Q_g * \frac{GCV}{1{,}000}$$

where: HI_g = heat input while combusting gas (mmBtu/hr)
Q_g = volumetric flow rate of gas combusted (kscf/hr)
GCV = Gross Calorific Value (or heating value) of gas combusted (Btu/scf)
1,000 = factor to convert from kscf to mmBtu

No. 2 Fuel Oil

$$HI_o = \frac{M_o * GCV * \rho * 60}{1{,}000{,}000}$$

where: HI_o = heat input while combusting oil (mmBtu/hr)
M_o = mass flow rate of oil combusted (gpm)
GCV = Gross Calorific Value (or heating value) of oil combusted (Btu/lb)
ρ = density of oil combusted (lb/gal)
60 = factor to convert from minutes to hours (60 min/hr)
1,000,000 = factor to convert from Btu to mmBtu (1,000,000 Btu/mmBtu)

Table 8-1 summarizes the applicable fuel analysis parameters that were used during this compliance test program to calculate heat input values. Copies of these fuel analyses are contained in Appendix 4 of this report.

Table 8-1. Fuel Analyses Results

Fuel	Gross Calorific Value (GCV)	Density
Natural Gas	1,036 Btu/scf	Not applicable
No. 2 Fuel Oil	19,093 Btu/lb	6.69 lb/gal

APPENDIX 1 – SUMMARY TABLES

Summary of Initial Compliance Testing Results for NO_x, CO, and VOC (Table A-1)
Summary of Initial Compliance Testing Results for Ammonia (Table A-2)
Summary of Operating Levels and Heat Input Rates (Table A-3)

TABLE A-1
SUMMARY OF INITIAL COMPLIANCE TESTING RESULTS FOR NOx, CO, and VOC

Progress Energy Hines PB2

Unit 2A - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC (or VOC) (ppmw as propane)	Raw THC (or VOC) (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC (or VOC) (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	11/08/03	1034-1157	164.0	98.5	3.47	13.87	2.91	0.81	0.68	0.14	0.42	9.29	0.46	0.39
	2	11/08/03	1210-1334	163.2	96.0	3.55	13.86	2.98	0.92	0.77	0.21	0.62	9.18	0.68	0.57
	3	11/08/03	1345-1518	162.2	95.4	3.63	13.87	3.05	0.92	0.77	0.16	0.49	9.32	0.54	0.45
	AVERAGE			163.1	96.0	3.55	13.87	2.98	0.88	0.74	0.17	0.51	9.26	0.56	0.47
					PERMIT LIMITS	N/A	N/A	3.5	N/A	16	N/A	N/A	N/A	N/A	2
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 2B - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC (or VOC) (ppmw as propane)	Raw THC (or VOC) (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC (or VOC) (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	11/07/03	1104-1229	168.2	98.9	3.79	13.98	3.23	0.74	0.63	0.46	1.37	9.20	1.51	1.28
	2	11/07/03	1248-1413	166.1	97.7	3.64	13.98	3.10	0.93	0.79	0.22	0.66	9.17	0.73	0.62
	3	11/07/03	1426-1551	165.8	97.5	3.85	13.97	3.27	1.01	0.86	0.17	0.52	9.33	0.57	0.48
	AVERAGE			166.7	98.0	3.76	13.97	3.20	0.89	0.76	0.28	0.85	9.23	0.93	0.80
					PERMIT LIMITS	N/A	N/A	3.5	N/A	16	N/A	N/A	N/A	N/A	2
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 2A - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC (or VOC) (ppmw as propane)	Raw THC (or VOC) (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC (or VOC) (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	11/12/03	0907-1007	160.0	94.1	10.29	13.79	8.53	1.28	1.06	0.15	0.45	7.34	0.49	0.40
	2	11/12/03	1027-1127	158.0	92.9	10.31	13.83	8.60	0.93	0.78	0.14	0.42	8.09	0.46	0.38
	3	11/12/03	1142-1242	157.0	92.4	11.37	13.86	9.52	0.77	0.64	0.03	0.08	7.68	0.08	0.07
	AVERAGE			158.3	93.1	10.65	13.83	8.88	0.99	0.83	0.11	0.32	7.70	0.34	0.29
					PERMIT LIMITS	N/A	N/A	12	N/A	30	N/A	N/A	N/A	N/A	10
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 2B - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC (or VOC) (ppmw as propane)	Raw THC (or VOC) (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC (or VOC) (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	11/11/03	1545-1645	160.0	94.1	12.42	13.87	10.43	0.67	0.56	0.03	0.09	4.25	0.09	0.08
	2	11/11/03	1704-1804	161.0	94.7	12.56	13.85	10.52	0.60	0.51	0.00	0.00	7.80	0.00	0.00
	3	11/11/03	1822-1922	163.0	95.9	12.56	13.85	10.50	0.63	0.53	0.00	0.00	8.20	0.00	0.00
	AVERAGE			161.3	94.9	12.55	13.86	10.51	0.63	0.53	0.01	0.03	6.75	0.03	0.03
					PERMIT LIMITS	N/A	N/A	12	N/A	30	N/A	N/A	N/A	N/A	10
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

NOTES:

- Permitted load = 170 MW (net) per test protocol
- NOx conversion factor = 1.194 e-07 lb/scf-ppm NOx
- CO conversion factor = 7.26 e-08 lb/scf-ppm CO
- NOx, O2, and CO values are corrected for system bias and drift
- All measured THC is assumed to be VOC.
- For this particular unit and fuel, propane was used as the calibration gas standard.

TABLE A-2
SUMMARY OF INITIAL COMPLIANCE TESTING RESULTS FOR AMMONIA

Progress Energy Hines PB2

Unit 2A - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Heat Input (mmBtu/hr)	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (ug)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/08/03	1034-1157	164.0	95.5	1831.6	193.8	3.23	2.91	43.437	1230.0	3254	3.74	13.87	3.14
	2	11/08/03	1210-1334	163.2	96.0	1824.7	195.2	3.25	2.98	43.020	1218.2	4594	5.34	13.86	4.47
	3	11/08/03	1345-1516	162.2	95.4	1817.8	195.6	3.28	3.05	45.220	1280.4	3853	4.26	13.87	3.57
	AVERAGE			163.1	96.0	1824.7	194.8	3.25	2.98	43.892	1242.9	3900	4.45	13.87	3.73
					PERMIT LIMITS	N/A	N/A	N/A	3.5	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 2B - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Heat Input (mmBtu/hr)	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (ug)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/07/03	1104-1229	168.2	98.9	1840.6	174.3	2.91	3.23	44.658	1264.5	2867	3.21	13.95	2.74
	2	11/07/03	1248-1413	166.1	97.7	1826.9	196.5	3.28	3.10	44.236	1252.6	3099	3.50	13.98	2.98
	3	11/07/03	1426-1551	165.8	97.5	1824.4	201.7	3.36	3.27	45.164	1279.4	3218	3.56	13.97	3.03
	AVERAGE			166.7	98.0	1832.6	190.8	3.18	3.20	44.693	1265.5	3081	3.42	13.96	2.92
					PERMIT LIMITS	N/A	N/A	N/A	3.5	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 2A - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Heat Input (mmBtu/hr)	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (ug)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/12/03	0907-1007	160.0	94.1	1669.9	420.6	7.01	8.53	42.905	1214.9	1532	1.78	13.79	1.48
	2	11/12/03	1027-1127	158.0	92.9	1650.9	433.5	7.22	8.60	43.557	1233.4	2896	3.32	13.83	2.77
	3	11/12/03	1142-1242	157.0	92.4	1640.2	439.0	7.32	9.52	41.658	1179.6	3276	3.93	13.86	3.29
	AVERAGE			158.3	93.1	1653.7	431.0	7.18	8.88	42.707	1209.3	2568	3.01	13.83	2.52
					PERMIT LIMITS	N/A	N/A	N/A	12	N/A	N/A	N/A	N/A	N/A	9
					COMPLIANCE?	N/A	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 2B - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Heat Input (mmBtu/hr)	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (ug)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/11/03	1545-1645	160.0	94.1	1645.8	560.4	9.34	10.43	44.803	1268.6	2511	2.80	13.87	2.35
	2	11/11/03	1704-1804	161.0	94.7	1660.1	545.8	9.09	10.52	44.707	1265.9	2388	2.67	13.85	2.23
	3	11/11/03	1822-1922	163.0	95.9	1673.6	550.6	9.18	10.59	45.152	1278.5	2266	2.51	13.85	2.10
	AVERAGE			161.3	94.9	1659.9	552.3	9.20	10.51	44.887	1271.0	2388	2.66	13.86	2.23
					PERMIT LIMITS	N/A	N/A	N/A	12	N/A	N/A	N/A	N/A	N/A	9
					COMPLIANCE?	N/A	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

NOTES:
- During compliance testing, NH3 injection rate(s) were at normal, "auto" conditions.
- NH3 slip (in ppm) = [(micrograms of NH3 catch / NH3 molecular weight)] / [(liters of sample volume / molar gas constant)]
- NH3 molecular weight = 17 lb/lb-mol
- Molar gas constant = liters of ideal gas per mole of substance = 24.050
- 1 dscf = 28.316 liters

TABLE A-3
SUMMARY OF OPERATING LEVELS AND HEAT INPUT RATES

Progress Energy Hines PB2

Unit 2A - Natural Gas									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Gas Flow (kscfh)	Gas Flow (hscfh)	GCV (Btu/scf)	Heat Input (mmBtu/hr)
High (Base)	1	11/08/03	1034-1157	164.0	96.5	1768.0	17679.5	1036	1831.6
	2	11/08/03	1210-1334	163.2	96.0	1761.3	17613.3	1036	1824.7
	3	11/08/03	1345-1510	162.2	95.4	1754.6	17546.1	1036	1817.8
	AVERAGE			163.1	96.0	1761.3	17613.0	1036	1824.7

Unit 2B - Natural Gas									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Gas Flow (kscfh)	Gas Flow (hscfh)	GCV (Btu/scf)	Heat Input (mmBtu/hr)
High (Base)	1	11/07/03	1104-1229	168.2	98.9	1782.4	17823.8	1036	1846.5
	2	11/07/03	1248-1413	166.1	97.7	1763.4	17633.8	1036	1826.9
	3	11/07/03	1426-1551	165.8	97.5	1761.0	17610.5	1036	1824.4
	AVERAGE			166.7	98.0	1768.9	17689.3	1036	1832.6

Unit 2A - No. 2 Fuel Oil									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Oil Flow (GPM)	Oil Density (lb/gal)	GCV (Btu/lb)	Heat Input (mmBtu/hr)
High (Base)	1	11/12/03	0907-1007	160.0	94.1	217.8	6.69	19093	1669.9
	2	11/12/03	1027-1127	158.0	92.9	215.3	6.69	19093	1650.9
	3	11/12/03	1142-1242	157.0	92.4	213.9	6.69	19093	1640.2
	AVERAGE			158.3	93.1	215.6	6.69	19093	1653.7

Unit 2B - No. 2 Fuel Oil									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Oil Flow (GPM)	Oil Density (lb/gal)	GCV (Btu/lb)	Heat Input (mmBtu/hr)
High (Base)	1	11/11/03	1545-1645	160.0	94.1	214.6	6.69	19093	1645.8
	2	11/11/03	1704-1804	161.0	94.7	216.5	6.69	19093	1660.1
	3	11/11/03	1822-1922	163.0	95.9	218.3	6.69	19093	1673.8
	AVERAGE			161.3	94.9	216.5	6.69	19093	1659.9

NOTES:

- mmBtu/hr (gas) = kscfh * (GCV/1,000)
- mmBtu/hr (oil) = (GPM * density * GCV * 60 min/hr) / 1,000,000 Btu/mmBtu
- kscfh = gas flow in thousand standard cubic feet per hour
- GPM = oil flow in gallons per minute

APPENDIX 4 – PLANT PROCESS DATA

DAHS Printouts
Fuel Analysis Results (Gas)
Fuel Analysis Results (Oil)
Turbine Manufacturer Performance Curves

Turbine Manufacturer Performance Curves

Ambient Temperature, F	GT Gross Power, MW	GT Fuel Flow to Gas Heater (As Shown in 22T5642)	GT Fuel Flow to Gas Heater Bypass (As Shown in 22T5642)	Total GT Fuel Flow, Lbs/hr	Fuel Gas Lower Heating Value	GT heat input	22T5642, Rev 4 Case #
F	MW	lbs/hr	lbs/hr	lbs/hr	Btu/lb	MBtu/hr	-
15	205.67	83960	5250	89210	21039	1877	4
	102.25	43190	9480	52670	21039	1108	6
59	183.12	76820	4690	81510	21039	1715	1
	81.95	40160	8520	48680	21039	1024	16
103	156.15	67550	4310	71860	21039	1512	5
	77.39	36330	7980	44310	21039	932	7

GT Heat Input versus Gross Power Output at Various Ambient Temperature, on Fuel Gas, per 22T5642 Rev. 004

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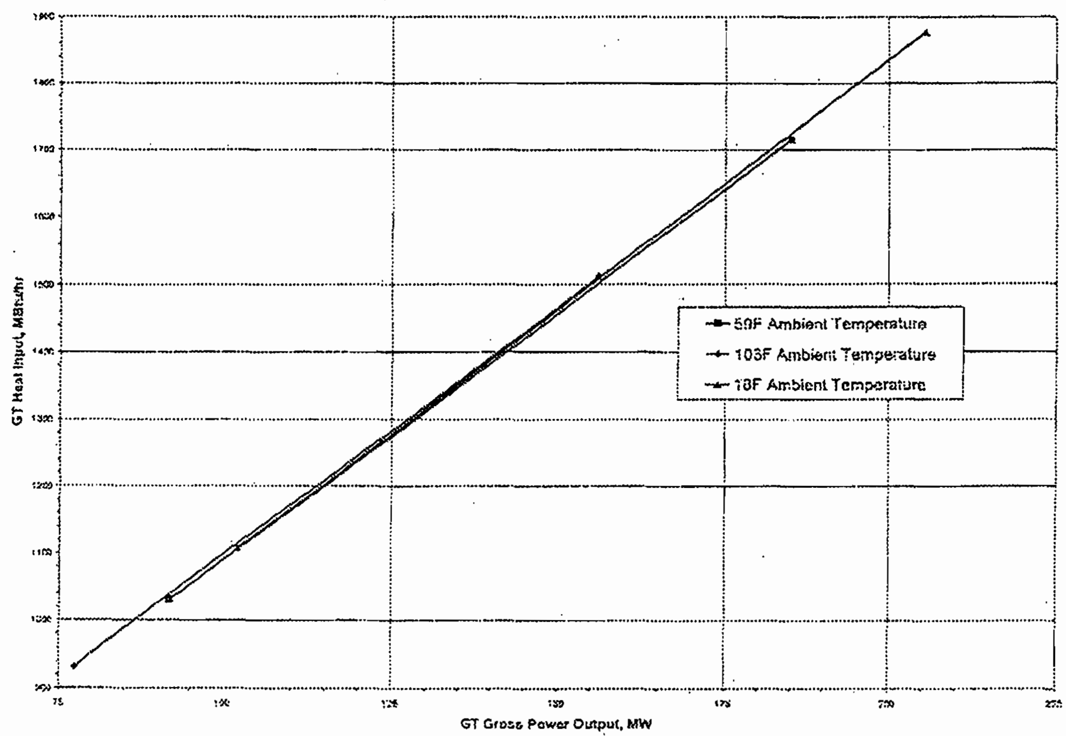

Progress Energy

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

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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

Unit	Regulation	Span	Manufacturer	Model	S/N
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

Unit	Test Dates	Monitor Range	Zero-Level[1] Response	Span-Level[2] Response	Performance[3] Specification
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

Unit	Response Time		Performance Specification
	Upscale	Downscale	
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

Unit	Test Date	Load (MW)	RATA Result		Performance Specification		
			@stack O_2	@15% O_2	Primary	Secondary	Tertiary
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

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[1]
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.

4.0 FACILITY DESCRIPTION

4.1 Facility Location

Progress Energy's Hines Energy Complex is located at County Road 555, Bartow, Polk County, Florida. For the PB3 project, Progress Energy is currently permitted to construct and operate (2) combustion turbine (CT) units (Units 3A and 3B), which are used for electricity generation and sale.

4.2 Unit Descriptions

Units 3A and 3B are Siemens Westinghouse 501 FD2 combustion turbines (CTs) with a maximum rated electrical output of ~170 MW each. Units 3A and 3B share a common steam turbine, rated at ~190 MW, for a total combined-cycle unit (CCU) system output of approximately 530 MW.

Units 3A and 3B are dual-fuel fired units that will combust natural gas as a primary fuel and No. 2 fuel oil as an "off-season" back-up fuel. The maximum heat input rating (based upon the HHV of the fuel, and an ambient temperature of 59 ^{o}F) of each unit while firing natural gas is 2,048 mmBtu/hr. The maximum heat input rating (based upon the HHV of the fuel, and an ambient temperature of 59 ^{o}F) of each unit while firing No. 2 fuel oil is 2,155 mmBtu/hr.

For the control of NO_x emissions, each unit uses dry low-NO_x burners (DLNBs) and selective catalytic reduction (SCR) (with ammonia injection) while firing natural gas. Each unit also uses water and SCR ammonia injection while firing No. 2 fuel oil. Each unit has its own HRSG used for combined-cycle operation; however, neither of the units will use duct burners for supplementary heat input. Appendix 2 of this report contains the combined process flow diagram for Units 3A and 3B.

4.3 Reference Methods Sampling Locations

The stack testing locations (as well as other pertinent, descriptive information) for each unit's outlet stack are described in Table 4-1. Appendix 2 contains the engineering stack diagrams and dimensions for Units 3A and 3B. All stack dimensions were verified for completeness and accuracy at the time of testing.

Table 4-1. Stack Testing Locations – Units 3A and 3B

Unit	Stack Exit Height (feet)	Test Platform Height (feet)	Stack ID (feet)	Accessed By?
3A	125	~110	19.0	Stairs + Ladder
3B	125	~110	19.0	Stairs + Ladder

5.0 REFERENCE METHOD COMPLIANCE TESTING PROCEDURES

This section includes a brief discussion of the test methods that were used for sampling and analysis at the Hines Energy Complex facility. Unless stated otherwise, all stack sampling was performed in accordance with the applicable test methods as prescribed in the referenced air permit. Any deviations from the standard procedures were previously noted in the test protocol that was previously submitted and approved.

During the compliance test program, all process data was electronically logged and printed out by the plant control room's data acquisition and handling system (DAHS). All process data taken during this test program is provided in Appendix 4 of this report.

5.1 Sample and Velocity Traverse (RM 1)

Velocity measurements were not required as part of this test program. Hence, RM 1, used for the determination of the number and location of sample points used for a given velocity or isokinetic traverse, was not applicable or relevant to this test program. Additionally, the verification of the absence of cyclonic flow was not necessitated.

It was proposed, however, that for all ammonia sampling (both fuels), a 3-point sample traverse be performed. These 3 points were proposed to be located at 0.4, 1.2, and 2.0 meters (i.e., 15.8, 47.2, and 78.7 inches) from the stack wall. Please reference Section 5.6 of this report for more detailed information concerning the selection of these particular traverse points. For the NO_x, CO, VOC, and O_2 sampling, the same 3-point traverse was also performed for each test condition. Appendix 2 of this report includes a summary of the calculated traverse points used during the test program.

5.2 Instrumental Reference Methods – NO_x (RM 7E), CO (RM 10), and O_2 (RM 3A)

Source emission testing was performed on both units to demonstrate compliance with the NO_x limits specified in the referenced air permit. RM 7E was used for the NO_x testing. For the NO_x sampling, a set of eight (8) 21-minute test runs and one (1) 60-minute test run was performed at high (i.e., normal) load on both units while combusting natural gas. A set of three 1-hour test runs was performed at high load on both units while combusting No. 2 fuel oil.

Testing was also performed to verify compliance with the CO limits as specified in the air permit. RM 10 was used to determine CO emissions. CO sampling was performed concurrently with the NO_x sampling.

O_2 concentrations were concurrently determined using the procedures described in RM 3A. The O_2 values were obtained in order to calculate values of NO_x and CO ppm corrected to 15% O_2, as well as VOC and NH_3 ppm corrected to 15% O_2. Since molecular weight values were not required for any part of this test program, CO_2 measurements were not necessitated (though they were taken). All O_2 sampling was performed concurrently with the NO_x, CO, VOC, and NH_3 sampling.

For the NO_x, CO, and O_2 measurements, the sample was extracted from the stack effluent through a heated sample probe and heated sample line to a sample conditioner where moisture was removed. The dried gas sample was then pumped to a distribution manifold where a portion of the sample gas was distributed to each analyzer. Since the possible presence of ammonia in the RM sample may bias any RM NO_x measurements high, a low-temperature molybdenum NO_x converter was used on the RM NO_x analyzers, in order to eliminate any possible ammonia interference.

In accordance with RM 3A and 7E, a three-point (i.e., zero-, mid- and high-level) calibration error check (i.e., direct analyzer calibration) was conducted on the O_2 and NO_x analyzers at the beginning of each test day, or when deemed necessary at the tester's discretion (e.g., switching units or gases, lengthy downtime, suspected drift, etc.). For RM 3A and 7E, the mid-level calibration gas is required to be 40-60% of span, while the high-level calibration gas is required to be 80-100% of span. This check was conducted by sequentially injecting the zero and span calibration gases directly into the analyzer, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the direct calibration, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (either nitrogen or cross-zero gas) and the span adjustment using only one of the two span gases. Acceptable system performance checks dictate that the difference between the analyzer responses and the respective cylinder tag values will not exceed $\geq$ 2% of span.

Zero and upscale system calibration checks (i.e., system bias calibration) were performed both before and after each test run in order to quantify reference measurement sampling system bias and calibration drift. In instances when the test runs immediately follow one another, the post-cal for the run immediately preceding a subsequent run was also be the pre-cal for that forthcoming run. Upscale was considered either the mid- or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the in-stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System bias and drift were then assessed. Sampling system bias is defined as the difference between the test run calibration check responses (system bias calibration) and the initial calibration error responses (direct analyzer calibration) as a percentage of span. Drift is defined as the difference between the pre- and post-test run system bias calibration responses.

If an acceptable post-test bias check result was obtained but the zero or upscale drift result exceeded the drift limit, the test run was considered valid; however, the direct analyzer calibration and system bias check procedures were repeated before conducting the next test run. A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded the bias specification. Again, the direct analyzer calibration and system bias check procedures must be repeated before conducting the next test run. Acceptable system performance checks dictate that system bias calibration checks will not exceed ≥ 5% of span or, for drift checks, ≥ 3% of span.

An NO to NO_2 converter efficiency test was successfully performed on the RM NO_x analyzers both before and after the test program as described in §5.6.1 of RM 20. The results of these tests are contained in Appendix 9 of this report. Note, however, that as a guideline and per §4.1.4 of RM 20, an NO_2 to NO converter is technically not necessary if the CT is operated at 90% or more of peak load capacity, which was the case during the NO_x sampling for this test program.

Concentrations of CO were also extracted continuously from the stack via the same sample transport system as that used for the O_2 and NO_x sampling. The calibration techniques for CO are similar to that for O_2 and NO_x, with the following exceptions: For CO, a four-point (i.e., zero-, low-, mid- and high-level) calibration error check (i.e., direct analyzer calibration) was conducted on the CO analyzer at the beginning of each test day, or when deemed necessary at the tester's discretion. For RM 10, the low-level calibration gas is required to be ~30% of span, the mid-level calibration gas ~60% of span, and the high-level gas is typically ~90-100% of span. For all system bias calibration checks, upscale was considered either the low-, mid-, or high-level gas, or whichever gas most closely approximated the flue gas level. The calibration performance specifications for CO were the same as that for the NO_x and O_2 measurements.

During this test program, in no instance did a direct calibration, system bias calibration, or drift comparison exceed the specifications as prescribed by the applicable test methods for O_2, NO_x, or CO. The actual calibrations, as well as the quality assurance checks of these calibrations, can be found in Appendix 3 of this report.

5.3 Instrumental Reference Methods – VOCs (RM 25A)

Testing for VOC concentrations was performed using RM 25A. A set of eight (8) 21-minute test runs and one (1) 60-minute test run was performed at high (i.e., normal) load on both units while combusting natural gas. A set of three 1-hour test runs was performed at high load on both units while combusting No. 2 fuel oil. The VOC sampling was performed concurrently with the NO_x and CO sampling.

The VOC measurements were extracted through the same heated probe and sample line as that of the NO_x, CO, and O_2 samples. However, once in the test trailer the VOC sample was directed through a different sample line in order to bypass the moisture knockout system used for the other pollutants, since VOC is measured on a hot/wet basis. All raw VOC data was calibrated and quantified as methane (CH_4). When calibrating with methane, it is not necessary to use any carbon correction factors. In addition, all total hydrocarbons (THC) measured were conservatively assumed to be VOC.

Prior to the test series, the heated sample line was heated to ~250 °F and the hydrocarbon analyzer was heated above 300 °F to prevent condensation. After the temperatures had stabilized, the hydrocarbon analyzer was ignited using hydrogen fuel and hydrocarbon free air. The analyzer(s) was then calibrated.

In accordance with RM 25A, a four-point (i.e., zero-, low-, mid- and high-level) calibration error check (i.e., a system tuning check) was conducted on the VOC analyzer at the beginning of each test day, or when deemed necessary at the tester's discretion. For RM 25A, the low-level calibration gas is required to be 25-35% of span, the mid-level calibration gas is required to be 45-55% of span, and the high-level calibration gas is required to be 80-90% of span. Unlike the direct calibration error check employed by RM 3A, 7E, and 10, RM 25A uses a system tuning check by shooting calibration gas throughout the entire sampling system, rather than immediately from the calibration gas cylinder(s) to the analyzer. This check was conducted by sequentially injecting the zero and span calibration gases throughout the sampling system, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the system tuning check, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas (either nitrogen or cross-zero gas) and the span adjustment using the high-level calibration gas. Based upon the zero- and high-level responses, the predicted response for the low- and mid-level gases were then calculated. Acceptable performance specifications for the system tuning checks dictate that the difference between the analyzer responses (either tuned [high] or predicted [low/mid]) and the respective cylinder tag values will not exceed $\geq$ 5% of the respective calibration gas tag value. For the zero gas, a performance specification of < 3% of <u>span</u> was used, since any % of the <u>tag value</u> for zero gas is 0.00 ppm.

Zero and upscale system calibration checks (i.e., system bias calibrations) were performed both before and after each test run in order to quantify reference measurement calibration drift. In instances when the test runs immediately followed one another, the post-cal for the run immediately preceding a subsequent run was also be the pre-cal for that forthcoming run. Upscale was considered either the low-, mid-, or high-level gas, or whichever gas most closely approximated the flue gas level. During these checks, the calibration gases were introduced into the sampling system at the stack probe outlet so that they were conveyed throughout the entire sampling system in the same manner as the flue gas samples. System drift was then assessed.

(Note that RM 25A does not assess system bias, nor does it correct any raw values for system bias). Drift is defined as the difference between the pre- and post-test run calibration responses. A run was considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeded a drift specification of ≥ 3% of span.

During this test program, in no instance did a system tuning check, system bias calibration, or drift comparison exceed the specifications as prescribed by RM 25A or the submitted test protocol. The actual calibrations, as well as the quality assurance checks of these calibrations, can be found in Appendix 3 of this report.

Note that, for this test program, it was not necessary to "subtract out" any non-VOC constituents, since the raw THC values measured were well below the permitted limits for all fuel and load conditions.

5.4 Instrumental Reference Method Calibration Gases and Equipment

Since RM 3A, 7E, 10, and 25A are instantaneous, "real time" test methods, NO_x, CO, and VOC compliance (ppm @ 15% O_2) was determined at the time of the initial compliance test.

The reference calibration gases used during this test program were certified following EPA Protocol analysis procedures. No calibration gas cylinders were used that contained less than 200 psi of gas, nor were any cylinders expired. Copies of the calibration gas "certificates of analysis" are provided in Appendix 9 of this report. RMB personnel have cross-checked and verified that the certification sheets provided in this test report match those cylinders/respective calibration gas concentrations used in the field during this test program.

Tables 5-1 and 5-2 summarize the analyzer spans and calibration gas values used for the RM measurements during the compliance testing for Units 3A and 3B. The spans used were based upon either a suitably accurate operating range for a particular monitor, or on concentrations exhibited by identical sources in prior test programs.

Table 5-1. RM Analyzer Spans and Calibration Gas Values – Natural Gas

		Calibration Gas Values (% of span)			
Analyzer	Span	Zero-Level	Low	Mid (40–60%)	High (80–100%)
NO_x	0–10 ppm	Nitrogen	Not Required	5.21 ppm	8.49 ppm
O_2	0–25%	Nitrogen	Not Required	12.00 %	21.00 %
		Zero-Level	Low (~30%)[1]	Mid (~60%)[1]	High (~90–100%)
CO	0–30 ppm	Nitrogen	9.00 ppm	16.19 ppm	27.50 ppm
		Zero-Level	Low (25–35%)	Mid (45–55%)	High (80–90%)
VOC (CH_4)[2]	0–30 ppm	Nitrogen	8.83 ppm	16.37 ppm	27.40 ppm

[1]A calibration gas tolerance band of ~±5% of the span required by RM 10 was used to increase calibration gas availability/possibilities.
[2]All RM 25A calibrations were quantified as methane.

Table 5-2. RM Analyzer Spans and Calibration Gas Values – No. 2 Fuel Oil

		Calibration Gas Values (% of span)			
Analyzer	Span	Zero-Level	Low	Mid (40–60%)	High (80–100%)
NO_x	0–18 ppm	Nitrogen	Not Required	8.49 ppm	14.90 ppm
O_2	0–25%	Nitrogen	Not Required	12.00 %	21.00 %
		Zero-Level	Low (~30%)[1]	Mid (~60%)[1]	High (~90–100%)
CO	0–30 ppm	Nitrogen	9.00 ppm	16.19 ppm	27.50 ppm
		Zero-Level	Low (25–35%)	Mid (45–55%)	High (80–90%)
VOC (CH_4)[2]	0–30 ppm	Nitrogen	8.83 ppm	16.37 ppm	27.40 ppm

[1]A calibration gas tolerance band of ~±5% of the span required by RM 10 was used to increase calibration gas availability/possibilities.
[2]All RM 25A calibrations were quantified as methane.

Table 5-3 summarizes the RM analyzer manufacturer, model, and principle of operation for each analyzer used during the test program. All of the RM analyzers used were those that are typical of the RMs used. In the event when the units were tested simultaneously, a separate, dedicated sample system and analyzer rack was used.

Table 5-3. RM Analyzer Descriptions

Method	Analyzer	Manufacturer	Model	Principle of Operation
7E	NO_x	Thermo Environmental	42C	Chemiluminescence
3A	O_2	Servomex	1440	Paramagnetic Cell Detector
10	CO	Thermo Environmental	48C	Gas Filter Correlation
25A	VOC	California Analytical	300-HMFID	Flame Ionization

5.5 Instrumental Reference Method Calculations

The RM analyzer measurements were recorded as 1-, 21-, and 60-minute averages on the test team's DAHS, where applicable. All test run concentration results were determined from the average gas concentrations measured during the run. For NO_x, CO, and O_2, the raw data values were adjusted for bias based upon the zero and upscale sampling system bias calibration results (per Equation 6C-1 presented in RM 6C, §8). For VOC, the raw, uncorrected run average values were used to determine compliance.

The NO_x, CO, and VOC ppm values corrected to 15% O_2 were calculated as follows:

$$C_{15} = C * \frac{5.9}{20.9 - \%O_2}$$

Where: C_{15} = Average pollutant concentration corrected to 15% O_2, expressed as ppm dry
C = Average pollutant concentration during respective compliance test run, expressed as ppm dry
O_2 = Average oxygen content during respective compliance test run, expressed as % dry

Note that, based upon the concurrently performed ammonia/moisture sampling (see Section 5.6 of this report), all VOC ppmw values were converted to ppmd, for the purposes of calculating VOC ppmd corrected to 15% O_2. The ppmw to ppmd conversion was performed as follows:

$$ppmd = \frac{ppmw}{1 - B_{ws}}$$

Where: ppmd = Average VOC concentration converted to ppm dry
ppmw = Average VOC concentration during respective compliance test run, measured as ppm wet
B_{ws} = Moisture content of stack gas, expressed as a decimal (e.g., 12% H_2O = 0.12 B_{ws})

5.6 Ammonia Slip Testing (CTM–027)

As part of this test program, ammonia slip testing was also performed on Units 3A and 3B using procedures based upon Conditional Test Method 027 (CTM–027). A set of three 1-hour test runs were performed on each unit while firing each fuel independently. All ammonia slip testing was performed concurrently with the compliance or RATA testing for the other pollutants. All ammonia injection rates during testing were at the normal rates anticipated to be used during subsequent, everyday unit operation.

For this test program, the following modifications to CTM–027 were previously proposed to and approved by FL DEP. These modifications were intended to make the test program easier to perform without compromising the integrity or accuracy of the test results:

- Samples were not collected isokinetically. It is understood that CTM-027 includes the isokinetic sampling procedure as it was originally intended (and validated) to collect particulate matter in conjunction with ammonia from a coal-fired boiler.

- It was proposed to use a Method 4-type sampling arrangement with a heated (at stack temperature) glass-lined probe. A nozzle and probe was connected in series with an impinger train set up per CTM-027. The sample was sampled non-isokinetically at the constant $\Delta H_{@}$ rate of the meter box, which is typically ~0.75 cfm. For 1-hour runs, a minimum of approximately forty-two (42) dry standard cubic feet (dscf) was collected for each test run.

- A single-port, three (3) point traverse of 0.4, 1.2, and 2.0 meters (i.e., 15.8, 47.2, and 78.7 inches) from the stack wall was used. This 3-point traverse was used to acquire a more representative stack sample, and was consistent with the "short" 3-point traverse used to perform RATAs under 40 CFR Part 75 and 40 CFR Part 60.

For this test program, the following CTM–027 procedures continued to be followed:

- The sample trains consisted of four (4) impingers. Impingers 1 and 2 each contained 100 ml of 0.1 N sulfuric acid (H_2SO_4). Impinger 3 was empty. Impinger 4 contained 200-300 g of indicating silica gel. Impingers 1 and 2 both contained Greenburg-Smith tips, while Impingers 3 and 4 were modified to not have tips, as required by CTM-027.

- All sample recoveries (e.g., probe and impinger rinses), transport, and analyses were performed according to the procedures specified by CTM-027. The sample recovery began by rinsing the nozzle and probe liner with deionized (DI) water to remove any particulate, then by rinsing with acetone to dry the glassware. The impingers were also weighed to the nearest

0.1 gram. The collected condensate measurements were then recorded on the CTM-027 field data sheets (as provided in Appendix 5 of this report). The impinger contents and rinses from the impingers and the connecting glassware were transferred to the appropriate, individual storage containers as required by the method. The samples, along with the proper chain of custody documentation, were then forwarded to the analytical laboratory. Ammonia concentrations were determined by ion chromatography equipped with a conductivity detector. The 0.1N sulfuric acid impinger blank and DI rinse blanks were also prepared according to the RM criteria.

This Method-4 type sampling arrangement was proposed since only the values of (a) dscf of sample volume and (b) the ammonia catch weight (μg) are required to calculate and quantify ammonia ppm (which was the only parameter needed for this test program). To quantify the dscf values, only the parameters of (1) actual sample volume, (2) meter box gamma, (3) meter box temperature, (4) barometric pressure, and (5) $\Delta H_{@}$ are needed. Using a Method-4 sampling arrangement provides all of these parameters. Isokinetic sampling, on the other hand, introduces several potential sources of sampling error, yet would yield essentially the same results as that of this proposed, modified approach.

All ammonia analyses were performed by Atmospheric Analysis and Consulting, Inc. These laboratory results are contained in Appendix 6 of this report.

For clarification, the following equation was used in order to quantify ammonia ppm.

$$C_{NH3} = \frac{\mu g/MW}{\left(V_{m(std)} * 28.316\right)/GC}$$

where:

	C_{NH3}	= ammonia concentration (ppm)
	μg	= micrograms of ammonia collected in sample run
	MW	= molecular weight of ammonia (17 lb/lb-mol)
	$V_{m(std)}$	= volume of sample taken during test run (dscf)
	28.316	= factor to convert from dscf to L of sample (1 ft^3 = 28.316 L) [note that the method requires that the sample volume be converted from dscf to L prior to calculating ppm]
	GC	= molar gas constant (24.056)

The moisture content of the gas stream was also determined simultaneously during the CTM-027 runs. The flue gas moisture content was needed to be quantified in order to convert all VOC ppmw values to ppmd.

5.7 Visible Emissions Testing (RM 9)

As part of this test program, VE readings were taken by a certified VE reader using RM 9. One thirty (30) minute test run was performed on Unit 3A and Unit 3B concurrently with one of the compliance test runs for natural gas and No. 2 fuel oil. VE readings were taken at 15-second intervals, or 120 readings per run. Six-minute block averages were calculated in order to determine compliance with the permit limit, which requires that the stack "opacity" be no more than 10 % per six-minute block. The VE field data and VE reader certification are contained in Appendix 7 of this report.

6.0 MISCELLANEOUS PERMIT REQUIREMENTS

6.1 Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (SAM)

The referenced air permit also includes emission "limitations" for sulfur dioxide (SO_2) and sulfuric acid mist (SAM). However, the concentrations of these pollutants were not required to be determined as part of the compliance test program. Rather, the referenced air permit provides alternate means and/or methods for determining these concentrations.

The fuels used on the units have sulfur limitations that effectively limit the potential emissions of SO_2 and SAM from the turbines and represent the BACT determination for these pollutants. Compliance with the fuel specifications (and subsequently and SO_2 and SAM limits) shall be demonstrated by keeping records of the sulfur contents of the fuels.

These records are currently maintained on site. Note that the natural gas documentation (total sulfur grains and GCV) that the facility maintains is also required under 40 CFR Part 75, Appendix D, and was submitted with the PB3 NO_x CEMS monitoring plan. Also note that the most recent (and current) sulfur analysis for the No. 2 fuel oil (% sulfur, GCV, and density) was submitted to FL DEP under separate cover on June 22, 2005.

6.2 Turbine Performance Curves

Specific Condition No. 7 of Air Permit No. PSD-FL-330 also requires that "manufacturer performance curves" be submitted within the same time frame after testing as the compliance test report. These performance curves specifically depict net plant output and fuel flow (which can be converted to heat input) versus ambient temperature, for the purpose of making site-specific corrections for heat input and power output (on an ambient conditions basis). The curves are provided in Appendix 8 of this report.

Note that initially these curves are theoretical in nature only, and can differ based upon any actual, real-world plant data that is accumulated during the forthcoming operating histories of the units.

7.0 Fuel Flow Meters and Heat Input Calculations

Natural gas fuel flow is measured using a dedicated orifice-plate type fuel flow meter for each unit. No. 2 fuel oil flow is measured using a Coriolis meter for each unit.

The Hines PB3 facility quantifies fuel flow for natural gas in thousand standard cubic feet per hour (kscfh) and No. 2 fuel oil in gallons per minute (GPM). The following equations are used in order to convert these units to heat input (mmBtu/hr), for each respective fuel:

Natural gas

$$HI_g = Q_g * \frac{GCV}{1{,}000}$$

where: HI_g = heat input while combusting gas (mmBtu/hr)
Q_g = volumetric flow rate of gas combusted (kscf/hr)
GCV = Gross Calorific Value (or heating value) of gas combusted (Btu/scf)
1,000 = factor to convert from kscf to mmBtu

No. 2 Fuel Oil

$$HI_o = \frac{M_o * GCV * \rho * 60}{1{,}000{,}000}$$

where: HI_o = heat input while combusting oil (mmBtu/hr)
M_o = mass flow rate of oil combusted (gpm)
GCV = Gross Calorific Value (or heating value) of oil combusted (Btu/lb)
ρ = density of oil combusted (lb/gal)
60 = factor to convert from minutes to hours (60 min/hr)
1,000,000 = factor to convert from Btu to mmBtu (1,000,000 Btu/mmBtu)

Table 7-1 summarizes the applicable fuel analysis parameters that were used during this compliance test program to calculate heat input values. Copies of these fuel analyses are contained in Appendix 4 of this report.

Table 8-1. Fuel Analyses Results

Fuel	Gross Calorific Value (GCV)	Density
Natural Gas	1,058 Btu/scf	Not applicable
No. 2 Fuel Oil	19,790 Btu/lb	6.72 lb/gal

APPENDIX 1 – SUMMARY TABLES

Summary of Initial Compliance Testing Results for NO_x, CO, and VOC (Table A-1)
Summary of Initial Compliance Testing Results for Ammonia (Table A-2)
Summary of Operating Levels and Heat Input Rates (Table A-3)

TABLE A-1
SUMMARY OF INITIAL COMPLIANCE TESTING RESULTS FOR NOx, CO, and VOC

Progress Energy Hines PB3

Unit 3A - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC [or VOC] (ppmw as methane)	Raw THC [or VOC] (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC [or VOC] (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	10/19/05	1116-1321	169.4	99.6	3.01	13.77	2.49	0.65	0.54	1.35	1.35	9.38	1.49	1.23
	2	10/19/05	1346-1538	170.7	100.4	2.86	13.71	2.35	0.67	0.55	0.73	0.73	10.38	0.81	0.67
	3	10/21/05	0745-0845	171.1	100.7	2.63	13.73	2.16	0.40	0.33	0.42	0.42	9.67	0.46	0.38
	AVERAGE			170.4	100.2	2.83	13.74	2.33	0.57	0.47	0.83	0.83	9.81	0.92	0.76
					PERMIT LIMITS	N/A	N/A	2.5	N/A	10	N/A	N/A	N/A	N/A	2
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 3B - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC [or VOC] (ppmw as methane)	Raw THC [or VOC] (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC [or VOC] (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	10/19/05	1116-1321	169.2	99.5	2.67	13.76	2.21	0.94	0.78	0.93	0.93	9.37	1.03	0.85
	2	10/19/05	1346-1538	170.8	100.5	2.72	13.74	2.24	0.89	0.73	1.10	1.10	9.66	1.22	1.00
	3	10/21/05	1930-2030	172.6	101.5	2.50	13.95	2.12	0.09	0.08	0.42	0.42	9.20	0.46	0.39
	AVERAGE			170.9	100.5	2.63	13.82	2.19	0.64	0.53	0.82	0.82	9.41	0.90	0.75
					PERMIT LIMITS	N/A	N/A	2.5	N/A	10	N/A	N/A	N/A	N/A	2
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 3A - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC [or VOC] (ppmw as methane)	Raw THC [or VOC] (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC [or VOC] (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	10/21/05	1345-1445	169.5	99.7	10.56	13.56	8.49	0.69	0.55	0.16	0.16	9.40	0.18	0.14
	2	10/21/05	1540-1640	168.6	99.2	10.01	13.59	8.08	0.40	0.32	0.27	0.27	8.68	0.30	0.24
	3	10/21/05	1705-1805	168.3	99.0	9.93	13.60	8.03	0.46	0.37	0.33	0.33	8.48	0.36	0.29
	AVERAGE			168.8	99.3	10.17	13.58	8.20	0.52	0.42	0.25	0.25	8.85	0.28	0.22
					PERMIT LIMITS	N/A	N/A	10	N/A	20	N/A	N/A	N/A	N/A	10
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

Unit 3B - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NOx (ppmd)	O2 (%d)	NOx (ppmd @ 15% O2)	CO (ppmd)	CO (ppmd @ 15% O2)	Raw THC [or VOC] (ppmw as methane)	Raw THC [or VOC] (ppmw as carbon)	Stack Moisture (% H2O)	Raw THC [or VOC] (ppmd as carbon)	VOC (ppmd @ 15% O2)
High (Base)	1	10/22/05	0818-0918	168.5	99.1	9.68	13.52	7.74	0.52	0.42	0.15	0.15	9.33	0.17	0.13
	2	10/22/05	0937-1037	166.8	98.1	9.55	13.54	7.66	0.49	0.39	0.45	0.45	9.54	0.50	0.40
	3	10/22/05	1101-1201	164.7	96.9	10.30	13.54	8.26	0.46	0.37	0.43	0.43	9.14	0.47	0.38
	AVERAGE			166.7	98.0	9.84	13.53	7.88	0.49	0.39	0.34	0.34	9.34	0.38	0.30
					PERMIT LIMITS	N/A	N/A	10	N/A	20	N/A	N/A	N/A	N/A	10
					COMPLIANCE?	N/A	N/A	YES	N/A	YES	N/A	N/A	N/A	N/A	YES

NOTES:
- Permitted load = 170 MW [net] per test protocol.
- NOx conversion factor = 1.194 e-07 lb/scf-ppm NOx
- CO conversion factor = 7.26 e-08 lb/scf-ppm CO
- NOx, O2, and CO values are corrected for system bias and drift.
- All measured THC is assumed to be VOC.
- For this particular unit and fuel, methane was used as the calibration gas standard.

TABLE A-2
SUMMARY OF INITIAL COMPLIANCE TESTING RESULTS FOR AMMONIA

Progress Energy Hines PB3

Unit 3A - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	10/19/05	1115-1215	169.5	99.7	199.9	3.33	2.49	40.448	1145.3	4129	5.10	13.77	4.22
	2	10/19/05	1345-1445	171.0	100.6	191.4	3.19	2.35	42.684	1208.6	3899	4.56	13.71	3.75
	3	10/19/05	1555-1655	170.2	100.1	195.8	3.26	2.37	42.626	1207.0	3928	4.61	13.73	3.79
	AVERAGE			170.2	100.1	195.7	3.26	2.40	41.919	1187.0	3985	4.76	13.74	3.92
					PERMIT LIMITS	N/A	N/A	2.5	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 3B - Natural Gas

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	10/19/05	1115-1215	169.1	99.5	152.3	2.54	2.21	44.133	1249.7	3845	4.35	13.76	3.60
	2	10/19/05	1345-1445	171.4	100.8	144.9	2.42	2.24	43.105	1220.6	2555	2.96	13.74	2.44
	3	10/19/05	1555-1655	170.0	100.0	147.5	2.46	2.25	42.394	1200.4	3059	3.61	13.77	2.98
	AVERAGE			170.2	100.1	148.2	2.47	2.23	43.211	1223.6	3153	3.64	13.76	3.01
					PERMIT LIMITS	N/A	N/A	2.5	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 3A - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	10/21/05	1345-1445	169.5	99.7	292.4	4.87	8.49	42.829	1212.7	3559	4.16	13.56	3.34
	2	10/21/05	1540-1640	168.6	99.2	300.0	5.00	8.08	40.489	1146.5	3727	4.60	13.59	3.71
	3	10/21/05	1706-1805	168.3	99.0	298.4	4.97	8.03	40.765	1154.3	3339	4.09	13.60	3.31
	AVERAGE			168.8	99.3	296.9	4.95	8.20	41.361	1171.2	3542	4.28	13.58	3.45
					PERMIT LIMITS	N/A	N/A	10	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

Unit 3B - No. 2 Fuel Oil

LOAD	RUN NO.	DATE	TIME	MW	% Of Load	NH3 Flow Rate (lb/hr)	NH3 Flow Rate (lb/min)	NOx (ppmd @ 15% O2)	Sample Volume (dscf)	Sample Volume (liters)	NH3 Catch (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	10/22/05	0818-0918	168.5	99.1	304.9	5.08	7.74	40.182	1137.8	3344	4.16	13.52	3.32
	2	10/22/05	0937-1037	166.8	98.1	294.2	4.90	7.66	41.407	1172.5	3394	4.10	13.54	3.28
	3	10/22/05	1101-1201	164.7	96.9	299.3	4.99	8.26	42.500	1203.4	2841	3.34	13.54	2.68
	AVERAGE			166.7	98.0	299.5	4.99	7.89	41.363	1171.2	3193	3.87	13.53	3.10
					PERMIT LIMITS	N/A	N/A	10	N/A	N/A	N/A	N/A	N/A	5
					COMPLIANCE?	N/A	N/A	YES	N/A	N/A	N/A	N/A	N/A	YES

NOTES:

- During compliance testing, NH3 injection rate(s) were at normal, "auto" conditions.
- NH3 slip (in ppm) = [(micrograms of NH3 catch / NH3 molecular weight)] / [(liters of sample volume / molar gas constant)]
- NH3 molecular weight = 17 lb/lb-mol
- Molar gas constant = liters of ideal gas per mole of substance = 24.056
- 1 dscf = 28.316 liters
- For Units 3A and 3B while firing natural gas, ammonia test run #3 was performed during RATA run #s 7 and 8

TABLE A-3
SUMMARY OF OPERATING LEVELS AND HEAT INPUT RATES

Progress Energy Hines PB3

Unit 3A - Natural Gas									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Gas Flow (kscfh)	Gas Flow (hscfh)	GCV (Btu/scf)	Heat Input (mmBtu/hr)
High (Base)	1	10/19/05	1116-1321	169.4	99.6	1666.4	16664.0	1058	1763.7
	2	10/19/05	1346-1538	170.7	100.4	1675.7	16757.0	1058	1773.6
	3	10/21/05	0745-0845	171.1	100.7	1677.7	16777.0	1057	1772.7
	AVERAGE			**170.4**	**100.2**	**1673.3**	**16732.7**	**1058**	**1770.0**

Unit 3B - Natural Gas									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Gas Flow (kscfh)	Gas Flow (hscfh)	GCV (Btu/scf)	Heat Input (mmBtu/hr)
High (Base)	1	10/19/05	1116-1321	169.2	99.5	1621.5	16214.7	1058	1715.5
	2	10/19/05	1346-1538	170.8	100.5	1657.9	16579.1	1058	1754.1
	3	10/21/05	1930-2030	172.6	101.5	1670.5	16705.0	1057	1765.7
	AVERAGE			**170.9**	**100.5**	**1650.0**	**16499.6**	**1058**	**1745.1**

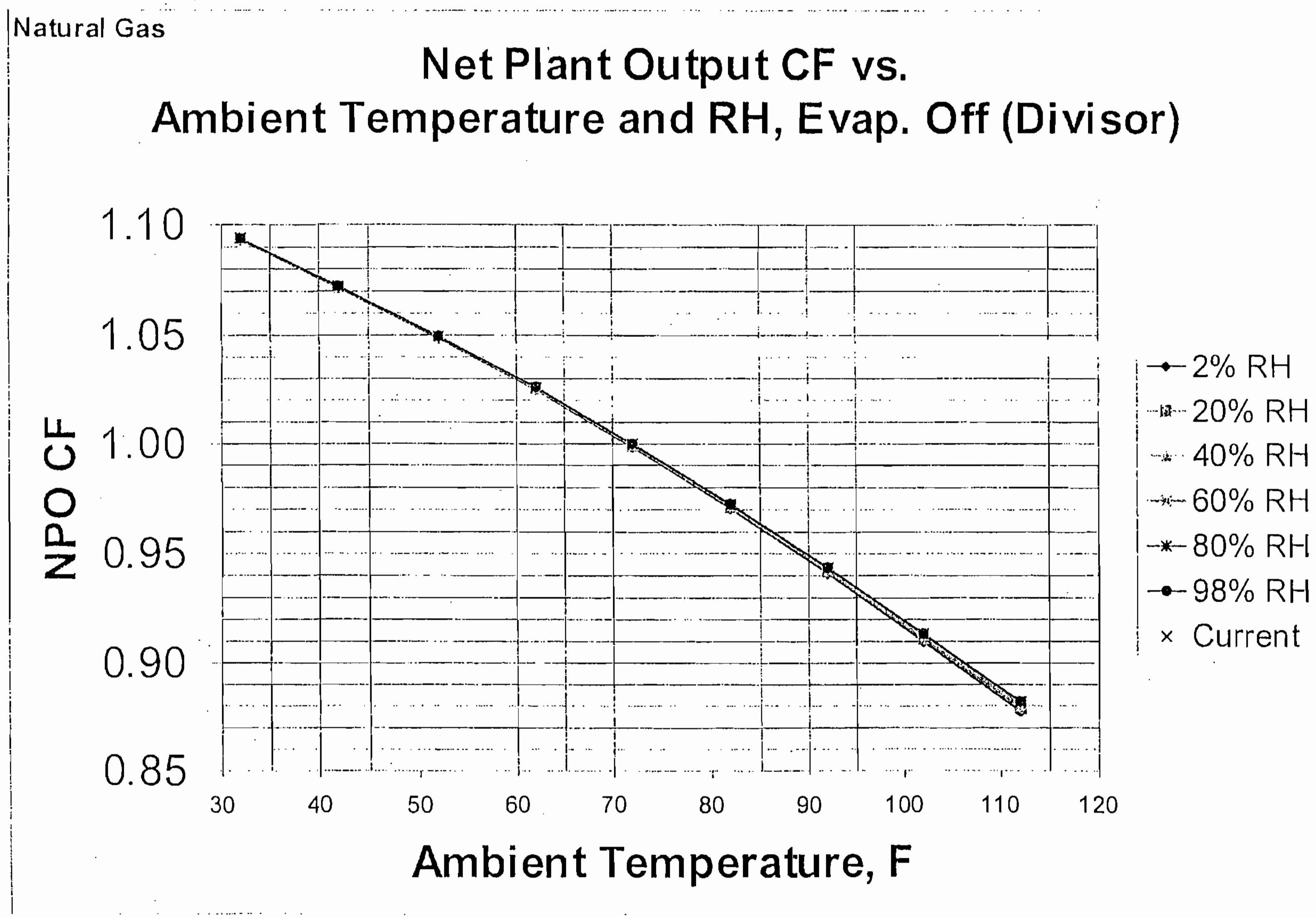
Unit 3A - No. 2 Fuel Oil									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Oil Flow (GPM)	Oil Density (lb/gal)	GCV (Btu/lb)	Heat Input (mmBtu/hr)
High (Base)	1	10/21/05	1345-1445	169.5	99.7	213.1	6.72	19790	1700.4
	2	10/21/05	1540-1640	168.6	99.2	212.4	6.72	19790	1694.8
	3	10/21/05	1705-1805	168.3	99.0	212.0	6.72	19790	1691.5
	AVERAGE			**168.8**	**99.3**	**212.5**	**6.72**	**19790**	**1695.6**

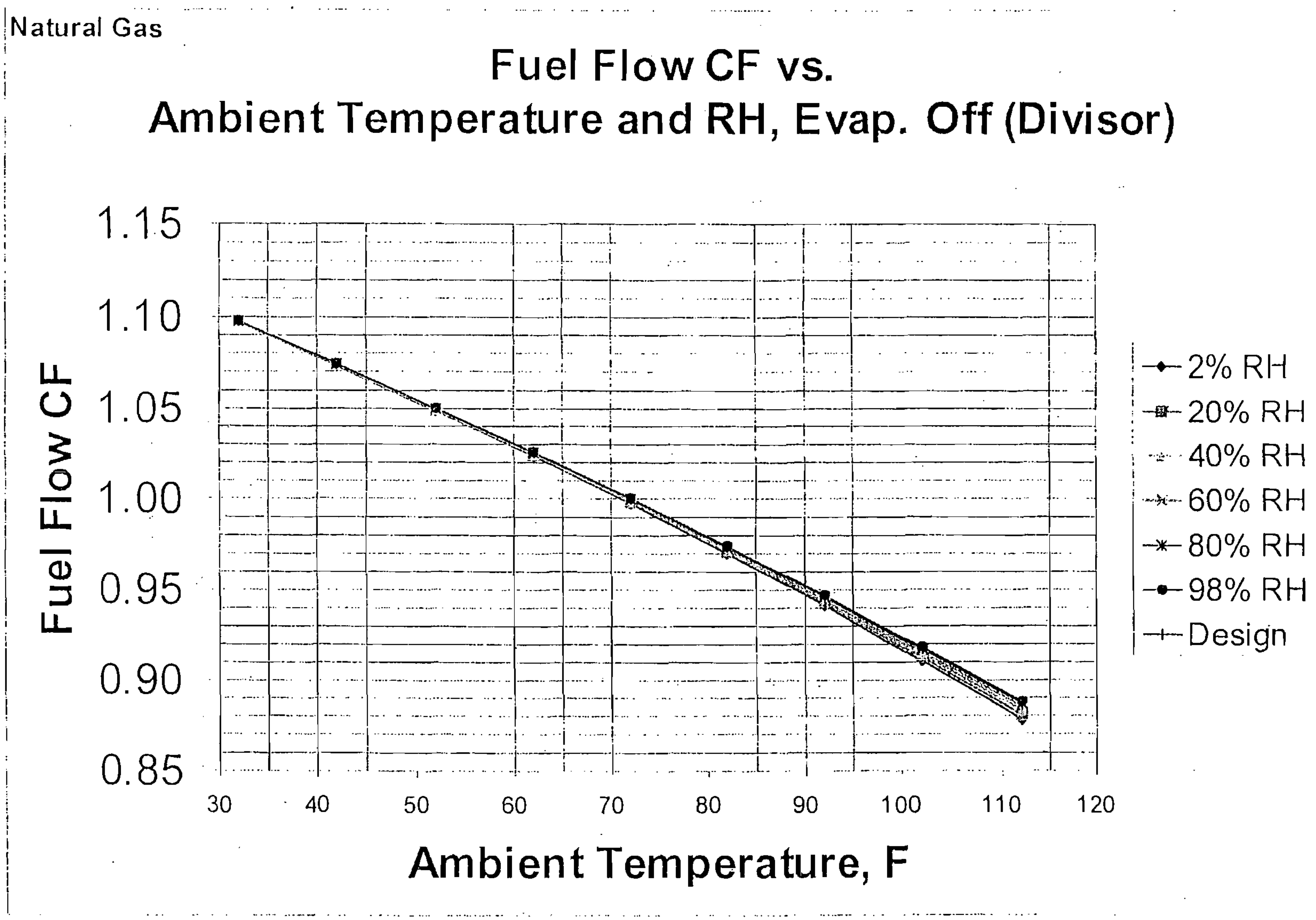
Unit 3B - No. 2 Fuel Oil									
LOAD	RUN NO.	DATE	TIME	MW	% Of Load	Oil Flow (GPM)	Oil Density (lb/gal)	GCV (Btu/lb)	Heat Input (mmBtu/hr)
High (Base)	1	10/22/05	0818-0918	168.5	99.1	223.2	6.72	19790	1780.8
	2	10/22/05	0937-1037	166.8	98.1	221.6	6.72	19790	1768.1
	3	10/22/05	1101-1201	164.7	96.9	219.5	6.72	19790	1751.4
	AVERAGE			**166.7**	**98.0**	**221.4**	**6.72**	**19790**	**1766.8**

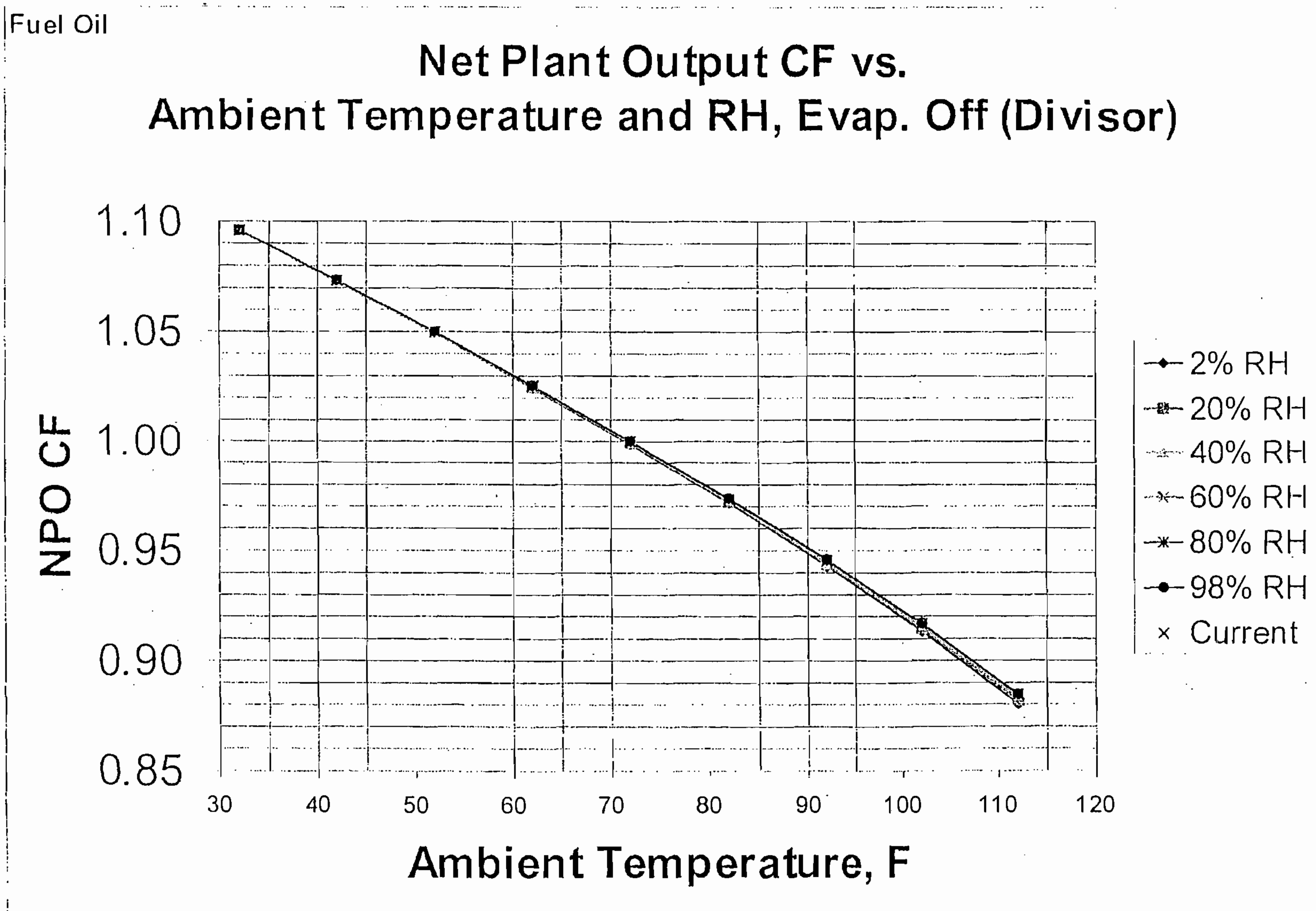
NOTES:

- mmBtu/hr (gas) = kscfh * (GCV/1,000)
- mmBtu/hr (oil) = (GPM * density * GCV * 60 min/hr) / 1,000,000 Btu/mmBtu
- kscfh = gas flow in thousand standard cubic feet per hour
- GPM = oil flow in gallons per minute

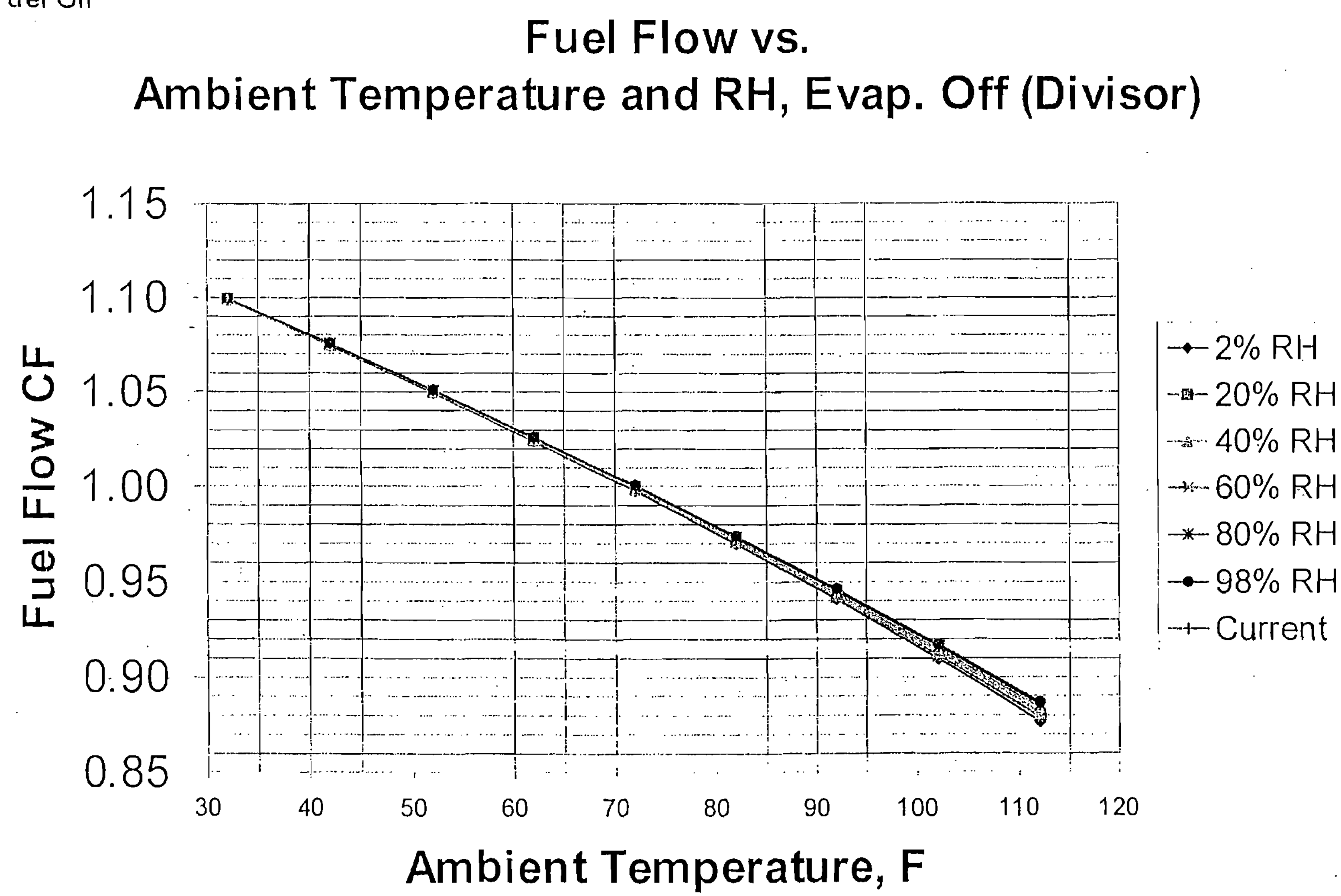
APPENDIX 8 – TURBINE MANUFACTURER PERFORMANCE CURVES


Natural Gas
Net Plant Output CF vs.
Ambient Temperature and RH, Evap. Off (Divisor)
1.10
1.05
1.00
0.95
0.90
0.85
NPO CF
30
40
50
60
70
80
90
100
110
120
Ambient Temperature, F
2% RH
20% RH
40% RH
60% RH
80% RH
98% RH
Current


Natural Gas
Fuel Flow CF vs.
Ambient Temperature and RH, Evap. Off (Divisor)
Fuel Flow CF
1.15
1.10
1.05
1.00
0.95
0.90
0.85
30
40
50
60
70
80
90
100
110
120
Ambient Temperature, F
2% RH
20% RH
40% RH
60% RH
80% RH
98% RH
Design


Fuel Oil
Net Plant Output CF vs.
Ambient Temperature and RH, Evap. Off (Divisor)
NPO CF
1.10
1.05
1.00
0.95
0.90
0.85
30
40
50
60
70
80
90
100
110
120
Ambient Temperature, F
2% RH
20% RH
40% RH
60% RH
80% RH
98% RH
Current

Fuel Oil



Fuel Flow vs.
Ambient Temperature and RH, Evap. Off (Divisor)
Fuel Flow CF
1.15
1.10
1.05
1.00
0.95
0.90
0.85
30
40
50
60
70
80
90
100
110
120
Ambient Temperature, F
2% RH
20% RH
40% RH
60% RH
80% RH
98% RH
Current

ATTACHMENT 4

REVISED BACT TABLES

Table B-3. Direct and Indirect Capital Costs for CO Catalyst, Combined- or Simple- Cycle Frame F Combustion Turbine

Cost Component	Costs	Basis of Cost Component
Direct Capital Costs		
CO Associated Equipment	$650,428	Vendor Quote
Flue Gas Ductwork	$44,505	Vatavauk,1990
Instrumentation	$65,043	10% of SCR Associated Equipment
Sales Tax	$39,026	6% of SCR Associated Equipment/Catalyst
Freight	$32,521	5% of SCR Associated Equipment/Catalyst
Total Direct Capital Costs (TDCC)	$831,523	
Direct Installation Costs		
Foundation and supports	$66,522	8% of TDCC and RCC;OAQPS Cost Control Manual
Handling & Erection	$116,413	14% of TDCC and RCC;OAQPS Cost Control Manual
Electrical	$33,261	4% of TDCC and RCC;OAQPS Cost Control Manual
Piping	$16,630	2% of TDCC and RCC;OAQPS Cost Control Manual
Insulation for ductwork	$8,315	1% of TDCC and RCC;OAQPS Cost Control Manual
Painting	$8,315	1% of TDCC and RCC;OAQPS Cost Control Manual
Site Preparation	$5,000	Engineering Estimate
Buildings	$0	
Total Direct Installation Costs (TDIC)	$254,457	
Total Capital Costs	$1,085,981	Sum of TDCC, TDIC and RCC
Indirect Costs		
Engineering	$108,598	10% of Total Capital Costs; OAQPS Cost Control Manual
Construction and Field Expense	$54,299	5% of Total Capital Costs; OAQPS Cost Control Manual
Contractor Fees	$108,598	10% of Total Capital Costs; OAQPS Cost Control Manual
Start-up	$21,720	2% of Total Capital Costs; OAQPS Cost Control Manual
Performance Tests	$10,860	1% of Total Capital Costs; OAQPS Cost Control Manual
Contingencies	$32,579	3% of Total Capital Costs; OAQPS Cost Control Manual
Total Indirect Capital Cost (TInDC)	$336,654	
Total Direct, Indirect and Capital Costs (TDICC)	$1,422,634	Sum of TCC and TInCC

Table B-4. Annualized Cost for CO Catalyst Frame F Combined- of Simple- Cycle Combustion Turbine

Cost Component	Cost	Basis of Cost Estimate
Diirect Annual Costs		
Operating Personnel	$6,240	8 hours/week at $15/hr
Supervision	$936	15% of Operating Personnel;OAQPS Cost Control Manual
Catalyst Replacement	$131,581	3 year catalyst life; based on Vendor Budget Quotes. Includes Spent Catalyst Credit of $125,000
Inventory Cost	$24,668	Capital Recovery (10.98%) for 1/3 catalyst
Contingency	$4,903	3% of Direct Annual Costs
Total Direct Annual Costs (TDAC)	$168,328	
Energy Costs		
Heat Rate Penalty	$331,675	$9.6/mmBtu addl fuel costs based 0.2% of MW output; EPA, 1993 (Page 6-20)
Total Energy Costs (TDEC)	$331,675	
Indirect Annual Costs		
Overhead	$4,306	60% of Operating/Supervision Labor
Property Taxes	$14,226	1% of Total Capital Costs
Insurance	$14,226	1% of Total Capital Costs
Annualized Total Direct Capital	$156,205	10.98% Capital Recovery Factor of 7% over 15 yrs times sum of TDICC
Total Indirect Annual Costs	$188,964	
Total Annualized Costs	$688,966	Sum of TDAC, TEC and TIAC
Cost Effectiveness	$3,956	per ton of CO Removed 174.15 tons/year CO Emissions Removed
	$4,048	per ton of Net Emission Reduction

Table B-5. Maximum Potential Incremental Emissions (TPY) with Oxidation Catalyst:Frame F CT

	Incremental Emissions (tons/year) of SCR		
Pollutants	Primary	Secondary	Total
Particulate		0.13	0.13
Sulfur Dioxide		0.05	0.05
Nitrogen Oxides		2.30	2.30
Carbon Monoxide	-174.2	1.38	-172.8
Volatile Organic Compounds		0.09	0.09
Total:	-174.2	3.95	-170.2
Carbon Dioxide (additional from gas firing)		2,188.1	2,188.1

Basis:

Lost Energy (mmBtu/year)	34,549
Secondary Emissions (lb/mmBtu): Assumes natural gas firing in NOx controlled steam unit.	
Particulate	0.0072
Sulfur Dioxide	0.0027
Nitrogen Oxides w/LNB	0.1333
Carbon Monoxide	0.0800
Volatile Organic Compounds	0.0052

Reference: Table 1.4-1 and 1.4-2, AP-42, Version 2/98

Table B-6. Comparison of Alternative BACT Control Technologies with Installing OC in HRSG: Frame F CT

	Alternative BACT Control Technologies	
	DLN Only	DLN with OC
Technical Assessment	Feasible	Available, Feasible and Demonstrated
Economic Impact [a]		
Capital Costs	included	$1,422,634
Annualized Costs	included	$688,966
Cost Effectiveness		
CO Removed (per ton of CO)	NA	$3,956
Environmental Impact [b]		
Total CO (TPY)	194	19
CO Reduction (TPY)	NA	-173
Net Pollutant Reduction	NA	-170
Additional Greenhouse Gas (CO2; tons/yr)	--	2,188
Energy Impacts [c]		
Energy Use (kWh/yr)	0	3,372,092
Energy Use (Equivalent Residential Customers/year)	0	281
Energy Use (mmBtu/yr) at 10,000 Btu/kWh	0	34,549
Energy Use (mmcf/yr) at 1,000 Btu/cf for natural gas	0	35

[a] See Tables B-3 and B-4 for detailed development of capital costs (including recurring costs) and annualized costs.

[b] See emission data presented in Table B-5.

[c] Energy impacts are estimated due to the lost energy from heat rate penalty for 8,760 hours per year.
Lost energy is based on 0.2 percent of 192 MW.

ATTACHMENT 5

VENDOR SPECS—DIESEL FIRE PUMP

UNITED MIDWEST, INC.

10679 Widmer
Lenexa, Kansas 66215
PHONE (913) 322-1288 • FAX (913) 322-1277

FAX 6-pages
928-7684

August 30, 2006

Adam Christenson
Bibb & Associates
8455 Lenexa Drive
Lenexa, Kansas 66214

Bartow Project

Adam;

Here are

Emission Data (2 pages) on the 300 HP Clarke / John Deere engine we would use to power the 2500 GP @ 135 psi pump.

Installation & Operation Data (2 pages) on the same engine

Predicted performance curve on the 10z8x20F pump we would use with the engine as well as the electric motor. Note that the shutoff pressure of this pump will be about 160 psi If your suction pressure exceeds 15 psi, please contact me.

The budget price I gave you of $255-260K was based on a job that included two engines (no electric motor), so was probably about $15K high.

Call me if you have any questions.

Al Brown

Al Brown

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JW6H-UF58

FIRE PUMP DRIVER

EMISSION DATA

FOR

EPA NSPS

6 Cylinders
Four *Cycle*
Lean *Burn*
Turbocharged

500 PPM SULFUR #2 DIESEL FUEL							
RPM	BHP (1)	FUEL GAL/HR (L/HR)	GRAMS / HP / HR			EXHAUST	
			NMHC+NOx	CO	PM (2)	°F (°C)	CFM (m^3/min)
1760	300	14 (53)	5.52	1.01	0.23	866 (463)	1642 (46)

6081H Base Model Engine Manufactured by John Deere Co.

Notes:

1) *Engines are rated at standard conditions of 29.61in. (7521 mm) Hg barometer and 77°F (25° C) inlet air temperature. (SAE J1349)*

2) *PM is a measure of total particulate matter, including PM_{10}.*

3) *These emissions values have been determined using engine test data with 500 parts per million (PPM) Sulfur content fuel.*

CLARKE

FIRE PROTECTION PRODUCTS
3133 EAST KEMPER ROAD
CINCINNATI, OH 45241

C131860 REV.A
19APR06 ACH

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Disclaimer

1. Stationary diesel-fueled compression ignition engines manufactured after July 1, 2006 for installations within U.S. are subject to the proposed EPA new source performance standards (the "NSPS"), Federal Code of Regulations Title 40 Chapter I, part 60.

2. The reverse side of this document shows the emissions from this model engine supplied by Clarke Fire Protection Products ("Clarke"). These emissions values are calculated based on an ISO 8178 part 4 D1 cycle weighted average of actual testing.

3. Actual test data in the field or other information established by the local air districts or the EPA that show actual emissions from an engine supplied by Clarke in excess of the NSPS limitations could indicate a violation of the NSPS and subject the owner and/or operator of the engine to penalties under federal law. Although Clarke believes that the engines supplied by Clarke comply with the NSPS based on the available data, for the foregoing reasons, Clarke cannot, and does not, guarantee that its engines will comply with the NSPS emission regulations.

4. CLARKE MAKES NO WARRANTIES OR GUARANTIES, EXPRESS OR IMPLIED, INCLUDING ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE OR OTHERWISE, THAT THE ENGINES SUPPLIED BY CLARKE WILL COMPLY WITH THE NSPS. CLARKE ALSO EXPRESSLY DISCLAIMS THAT THE ENGINES SUPPLIED BY CLARKE WILL, IN FACT, COMPLY WITH THE NSPS. IN NO EVENT SHALL CLARKE BE LIABLE FOR SPECIAL, INCIDENTAL OR CONSEQUENTIAL DAMAGES ARISING OUT OF OR IN CONNECTION WITH THESE TERMS AND CONDITIONS OR THE ENGINES SUPPLIED BY CLARKE OR FOR INDEMNIFICATION OF BUYER ON ACCOUNT OF ANY CLAIM ASSERTED AGAINST BUYER, OR FOR ANY OTHER DAMAGE OF ANY KIND, WHETHER DIRECT OR INDIRECT, IF THE ENGINES SUPPLIED BY CLARKE DO NOT COMPLY WITH THE NSPS.

8 June 2006

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CLARKE

Fire Protection Products

JW6H-UF58
INSTALLATION & OPERATION DATA

Basic Engine Description

Engine Manufacturer	John Deere Co.
Ignition Type	Compression (Diesel)
Number of Cylinders	6
Bore and Stroke - in.(mm)	4.56 (116) x 5.06 (129)
Displacement - $in.^3$ (L)	496 (8.1)
Compression Ratio	15.7:1
Valves per cylinder - Intake	1
Exhaust	1
Combustion System	Direct Injection
Engine Type	In-Line, 4 Stroke Cycle
Aspiration	Turbocharged
Firing Order (CW Rotation)	1-5-3-6-2-4
Charge Air Cooling Type	Raw Water Cooled
Rotation (Viewed from Front) - Clockwise	Standard
Counter-Clockwise	Not Available
Engine Crankcase Vent System	Open
Installation Drawing	D-495

Cooling System

	1760
Engine H_2O Heat -Btu/sec.(kW)	131 (138)
Engine Radiated Heat - Btu/sec.(kW)	32 (34)
Heat Exchanger Minimium Flow	
60°F (15°C) Raw H_2O - gal/min. (L/min.)	35 (132)
95°F (35°C) Raw H_2O - gal/min. (L/min.)	39 (146)
Heat Exchanger Maximum Cooling H_2O	
Inlet Pressure - bar ($lb./in.^2$) (kPa)	4 (60) (400)
Flow - gal./min (L/min.)	80 (302)
Thermostat, Start to Open - °F (°C)	180 (82)
Fully Opened - °F (°C)	202 (94)
Engine Coolant Capacity - qt. (L)	23 (22)
Coolant Pressure Cap - $lb./in.^2$(kPa)	10 (69)
Maximum Engine H_2O Temperature - °F (°C)	200 (93)
Minimum Engine H_2O Temperature - °F (°C)	160 (71)

Electric System - DC

System Voltage (Nominal)	12
Battery Capacity for Ambients Above 32°F (0°C)	
Voltage (Nominal)	12
Qty. per Battery Bank	1
SAE size per J537	8D-900
CCA @ 0°F (-18°C)	900
Reserve Capacity - Minutes	430
Battery Cable Circuit*, Max Resistance - ohm	0.0017
Battery Cable Minimum Size	
0 -120 in. Circuit* Length	00
121 - 160 in. Circuit* Length	000
161 - 200 in. Circuit* Length	0000
Charging Alternator Output - Amp	40
Starter Cranking Amps - @ 60°F (15°C)	495

**Positive and Negative Cables Combined Length*

NOTE: This engine is Intendend For Indoor Installation Or In A Weatherproof Enclosure. *(Continued)*

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CLARKE Fire Protection Products

JW6H-UF58
INSTALLATION & OPERATION DATA (Continued)

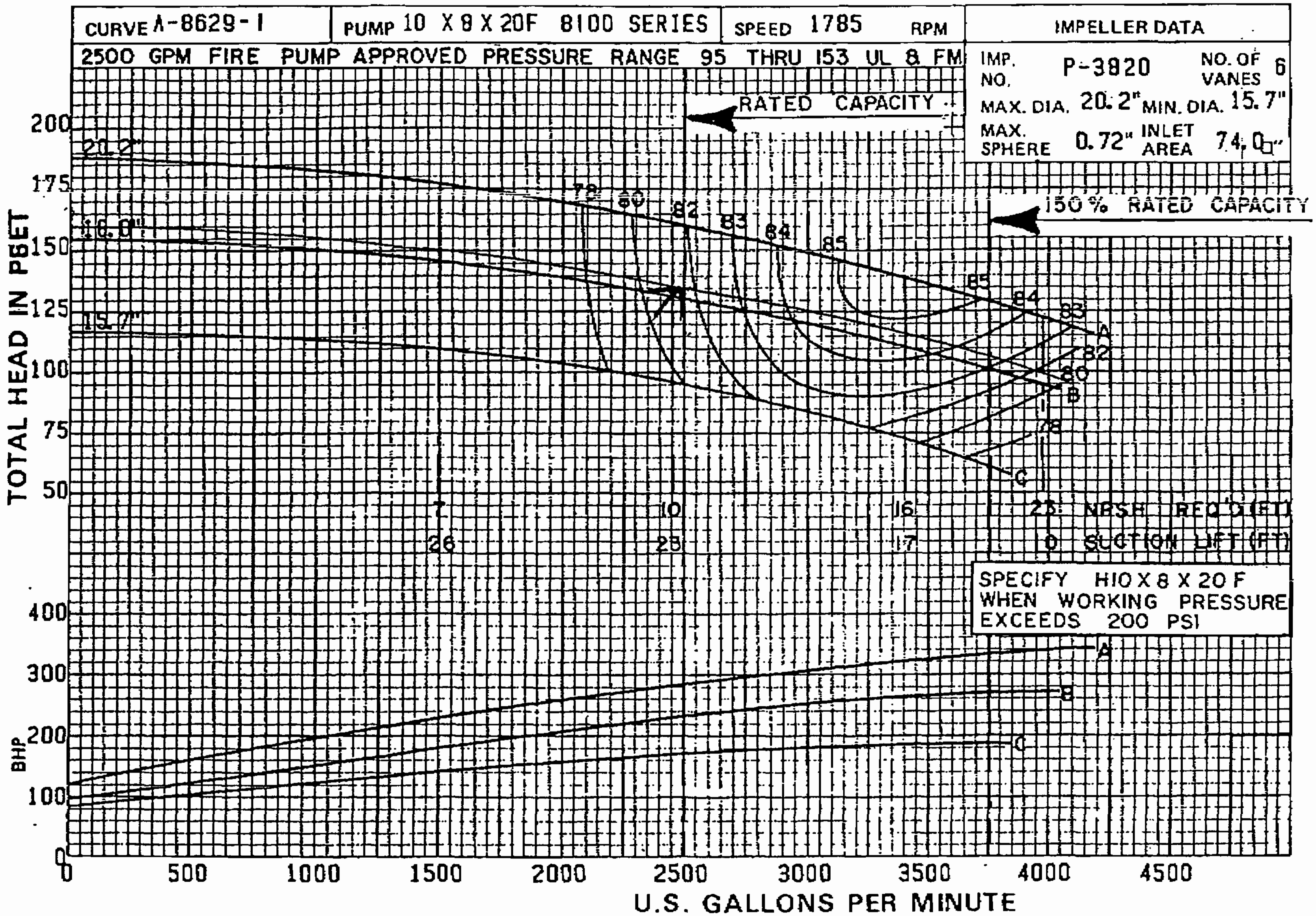
Exhaust System	**1760**
Exhaust Flow - ft.^{3}/min. (m^3/min.)	1642 (46)
Exhaust Temperature - °F (°C)	866 (463)
Maximum Allowable Back Pressure - in. H_2O (kPa)	26 (6.6)
Minimum Exhaust Pipe Dia. - in. (mm)**	6 (152)
Fuel System	
Fuel Consumption - gal./hr. (L/hr.)	14 (53)
Fuel Return - gal./hr. (L/hr)	62.5 (237)
Total Supply Fuel Flow - gal./hr (L/hr.)	76.5 (290)
Fuel Pressure - lb./in.^{2} (kPa)	25-35 (172-241)
Minimum Line Size - Supply - in. (mm)**	.50 Sch. 40 - Black
Minimum Line Size - Return - in. (mm)**	.37 Sch. 40 - Black
Maximum Allowable Fuel Pump Suction	
With Clean Filter - in. H_2O (mH_2O)	31 (0.8)
Maximum Allowable Fuel Head above Fuel pump, Supply or Retrun - ft(m)	9 (2.7)
Fuel Filter Micron Size	8
Heater System	
Jacket Water Heater	Standard
Wattage (Nominal)	2500
Voltage - AC, 1P	230 (+5%, -10%)
Optional Voltage - AC, 1P	115 (+5%, -10%)
Lube Oil Heater Wattage	
(Required Option When Ambient is Below 40°F (4°C)	150
Induction Air System	
Air Cleaner Type	Indoors Service Only - Washable
Air Intake Restriction Maximum Limit	
Dirty Air Cleaner - in. H_2O (kPa)	14 (3.5)
Clean Air Cleaner - in. H_2O (kPa)	6 (1.5)
Engine Air Flow - ft.^{3}/min. (m^3/min.)	692 (20)
Maximum Allowable Temperature (Air To Engine Inlet) - °F (°C)***	130 (54)
Lubrication System	
Oil Pressure - normal - lb./in.^{2} (kPa)	30-55 (207-379)
In Pan Oil Temperature - °F (°C)	190-220 (88-104)
Oil Pan Capacity - High - qt. (L)	32 (30)
Total Oil Capacity with Filter - qt. (L)	34 (32)
Performance	
BMEP - lb./in.^{2} (kPa)	272 (1877)
Piston Speed - ft./min. (m/min.)	1484 (452)
Mechanical Noise - dB(A) @ 1M	C131482
Power Curve	C131311

*** Based On Nominal System. Flow Analysis Must Be Done To Assure Adherance To System Limitations. (Minimum Exhaust pipe Diameter is based on 15 feet of pipe, one elbow, and a silencer pressure drop no greter than one half the max. allowable back pressure.)*

**** Review For Power Deration If Air Entering Engine Exceeds °77F (25°C)*

C131384 rev B
MJD JUN05

BEST AVAILABLE COPY



Curves show performance with clear water at 85°F. If specific gravity is other than 1.0, BHP must be corrected.

ATTACHMENT 6

AIR MODELING ANALYSIS

TABLE 18-1

SUMMARY OF PM_{10} EMITTING FACILITIES CONSIDERED IN THE AAQS AND PSD CLASS II INCREMENT CONSUMPTION ANALYSES

			UTM Coordinates		Relative to the Bartow Plant[a]						
Plant ID	Facility Name	County	East (km)	North (km)	X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum PM Emissions (TPY)	Q, (TPY) Emission Threshold [b] Dist x 20	Include in Modeling Analysis ?
Modeling Area [c]											
1030117	Pinellas Co. Resource Recovery Facility	Pinellas	335.2	3084.1	-7.2	1.5	282	7.4	657.0	147	Yes
Screening Area[d]											
1030012	Progress Energy- Higgins Plant	Pinellas	336.5	3098.4	-5.9	15.8	340	16.9	1,259.8	337	Yes
0570038	TECO, Hookers Point	Hillsborough	358.0	3091.0	15.6	8.4	62	17.7	1,536.4	354	Yes
0570040	TECO Bayside Power Station	Hillsborough	360.1	3087.5	17.7	4.9	75	18.4	5,267.0	367	Yes
0570094	Mosaic - Big Bend Terminal	Hillsborough	361.0	3076.2	18.6	-6.4	109	19.7	10.0	393	Yes [e]
0570127	Mckay Bay Refuse-To-Energy Facility	Hillsborough	360.2	3092.2	17.8	9.6	62	20.2	172.2	405	Yes [e]
0570008	Mosaic Riverview Facility	Hillsborough	362.9	3082.5	20.5	-0.1	90	20.5	328.8	410	Yes [e]
0570039	TECO, Big Bend Station	Hillsborough	361.9	3075.0	19.5	-7.6	111	20.9	5,942.0	419	Yes
0570261	Hillsborough Cty. RRF	Hillsborough	368.2	3092.7	25.8	10.1	69	27.7	92.0	554	Yes [e]
	Imc - Agrico Co. (Pierce)		404.1	3079.0	-16.7	-24.3	214	29.5	-311.4	590	Yes [e]
0810010	FPL - Manatee Power Plant	Manatee	367.3	3054.2	24.9	-28.4	139	37.8	9,471.8	755	Yes
	Stauffer Tarpon Springs	Pinellas	325.6	3116.7	-16.8	34.1	334	38.0	-455.3	760	Yes [e]
1010017	Anclote Power Plant	Pasco	327.4	3120.7	-15.0	38.1	339	40.9	5,490.0	818	Yes

[a] The location of the Progress Energy Bartow plant in UTM Coordinates: East 342.4 km
North 3082.6 km

[b] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the screening area and its emission rate is greater than the product of "Distance x 20".

[c] The "Modeling Area" for the project is estimated to be 10.0 km. Pollutant concentrations were predicted in this area.

[d] The "Screening Area" is the area beyond the modeling area in which background sources were considered for modeling and extended out to 40 km from the plant.

[e] Additional facilities were modeled since the maximum PM_{10} impacts due to the project alone were relatively close to the 24-hour average PSD Class II increment.

TABLE 18-2
SUMMARY OF SO_2 EMITTING FACILITIES CONSIDERED IN THE AAQS AND PSD CLASS II INCREMENT CONSUMPTION ANALYSES

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to the Bartow Plant[a] X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum SO_2 Emissions (TPY)	Q, (TPY) Emission Threshold[b] Dist x 20	Include in Modeling Analysis ?
Modeling Area[c]											
0570028	National Gypsum Co.	Hillsborough	348.8	3,082.7	6.4	0.1	89	6.4	151.6	SIA	Yes
1030117	Pinellas Co. Resource Recovery Facility	Pinellas	335.2	3,084.1	-7.2	1.5	282	7.4	2,235.0	SIA	Yes
Screening Area[d]											
1030013	Progress Energy Florida, Inc. - Bayboro	Pinellas	338.8	3,071.3	-3.6	-11.3	198	11.9	6,848.0	37	Yes
0570041	Florida Health Sciences Ctr, Inc	Hillsborough	356.4	3,091.0	14.0	8.4	59	16.3	58.9	127	No
1030026	R.E. Purcell Construction Co., Inc.	Pinellas	326.2	3,086.9	-16.2	4.3	285	16.8	74.7	135	No
0570286	Tampa Bay Shipbuilding & Repair Company	Hillsborough	358.0	3,089.0	15.6	6.4	68	16.9	12.0	137	No
1030012	Progress Energy Florida - Higgins	Pinellas	336.5	3,098.4	-5.9	15.8	340	16.9	24,803.7	137	Yes
0570089	St. Joseph's Hospital	Hillsborough	353.3	3,095.9	10.9	13.3	39	17.2	14.5	144	No
0570038	TECO, Hookers Point	Hillsborough	358.0	3,091.0	15.6	8.4	62	17.7	10	154	No
0571290	Tarmac America, LLC	Hillsborough	359.9	3,087.8	17.5	5.2	73	18.3	21.9	166	No
0571209	Apac-Southeast, Inc Central Florida Div.	Hillsborough	359.9	3,088.1	17.5	5.5	73	18.3	58.5	166	No
0570040	Tampa Electric Company - Bayside Power Station	Hillsborough	360.1	3,087.5	17.7	4.9	75	18.4	496.1	167	Yes
0570080	Marathon Ashland Petroleum Llc	Hillsborough	359.5	3,091.7	17.1	9.1	62	19.4	35.2	187	No
0570127	McKay Bay Refuse-To-Energy Facility	Hillsborough	360.2	3,092.2	17.8	9.6	62	20.2	156.0	205	No
0570008	Mosaic Fertilizer, LLC - Riverview	Hillsborough	362.9	3,082.5	20.5	-0.1	90	20.5	6,506.1	210	Yes
0570039	Tampa Electric Company - Big Bend	Hillsborough	361.9	3,075.0	19.5	-7.6	111	20.9	364,177.5	219	Yes
0571242	New Ngc, Inc., D/B/A National Gypsum Com	Hillsborough	364.7	3,075.6	22.3	-7.0	107	23.4	79.0	267	No
0570057	Enviro Focus Technologies, LLC	Hillsborough	364.0	3,093.5	21.6	10.9	63	24.2	1,015.0	284	Yes
0570223	Apac-Southeast, Inc Central Florida Div.	Hillsborough	364.0	3,098.1	21.6	15.5	54	26.6	80.0	332	No
0810024	FPL - Port Manatee Oil Storage Facility	Manatee	349.1	3,056.5	6.7	-26.1	166	26.9	145.1	339	No
0570261	Hillsborough Cty. Resource Recovery Fac.	Hillsborough	368.2	3,092.7	25.8	10.1	69	27.7	431.7	354	Yes
0571279	Florida Gas Transmission Company	Hillsborough	372.2	3,102.4	29.8	19.8	56	35.8	14.9	515	No
1010027	Ajax Paving Industries, Inc.	Pasco	342.2	3,119.2	-0.2	36.6	360	36.6	28.0	532	No
1010041	Apac- Southeast, Inc., Central Fl. Div	Pasco	340.7	3,119.5	-1.7	36.9	357	36.9	157.7	539	No
1030044	Suncoast Paving, Inc.	Pinellas	327.7	3,116.7	-14.7	34.1	337	37.1	37.4	542	No
0570076	Apac Southeast, Inc. - Central Fl. Div.	Hillsborough	372.1	3,105.4	29.7	22.8	52	37.4	31.1	549	No
0810010	Florida Power & Light - Manatee	Manatee	367.3	3,054.2	24.9	-28.4	139	37.8	83,542.6	555	Yes
1010017	Progress Energy Florida, Inc. - Anclote Power Plant	Pasco	327.4	3,120.7	-15.0	38.1	339	40.9	120,811.0	618	Yes

[a] The location of the Progress Energy Bartow plant in UTM Coordinates: East 342.4 km; North 3082.6 km

[b] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the screening area and its emission rate is greater than the product of "Distance x 20".

[c] The "Modeling Area" for the project is estimated to be 10.0 km. Pollutant concentrations were predicted in this area.

[d] The "Screening Area" is the area beyond the modeling area in which background sources were considered for modeling and extended out to 40 km from the plant.

TABLE 18-3
SUMMARY OF NO_x EMITTING FACILITIES CONSIDERED IN THE AAQS AND PSD CLASS II INCREMENT CONSUMPTION ANALYSES

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to the Bartow Plant[a] X (km)	Y (km)	Direction (deg.)	Distance (km)	Maximum NOx Emissions (TPY)	Q, (TPY) Emission Threshold[b] Dist x 20	Include in Modeling Analysis ?
Modeling Area[c]											
0570028	National Gypsum Co.	Hillsborough	348.8	3,082.7	6.4	0.1	89.2	6.4	160	SIA	Yes
1030117	Pinellas Co. Resource Recovery Facility	Pinellas	335.2	3084.1	-7.2	1.5	282	7.4	2,697	SIA	Yes
Screening Area[d]											
1030013	Progress Energy- Bayboro Plant	Pinellas	338.8	3,071.3	-3.6	-11.3	197.7	11.9	3,838	37	Yes
1030012	Progress Energy- Higgins Plant	Pinellas	336.5	3098.4	-5.9	15.8	340	16.9	4,049	137	Yes
0570038	TECO, Hookers Point	Hillsborough	358.0	3091.0	15.6	8.4	62	17.7	582	154	Yes
0570040	TECO Bayside Power Station	Hillsborough	360.1	3087.5	17.7	4.9	75	18.4	708	167	Yes
0570442	Gulf Marine Repair Corp.	Hillsborough	360.3	3,091.9	17.9	9.3	62.5	20.2	127	203	No
0570127	Mckay Bay Refuse-To-Energy Facility	Hillsborough	360.2	3092.2	17.8	9.6	62	20.2	679	205	Yes
0570008	Mosaic Riverview Facility	Hillsborough	362.9	3082.5	20.5	-0.1	90	20.5	313	210	Yes
0570039	TECO, Big Bend Station	Hillsborough	361.9	3075.0	19.5	-7.6	111	20.9	82,622	219	Yes
0570029	Kinder Morgan Port Sutton Terminal	Hillsborough	362.5	3,089.0	20.1	6.4	72.3	21.1	302	222	Yes
0810002	Piney Point Phosphates, Inc.	Manatee	349.7	3,057.3	7.3	-25.3	164.0	26.3	169	326	No
0570261	Hillsborough Cty. RRF	Hillsborough	368.2	3092.7	25.8	10.1	69	27.7	768	354	Yes
0570076	Delta Asphalt	Hillsborough	372.1	3,105.4	29.7	22.8	52.5	37.4	192	549	No
0810010	FPL - Manatee Power Plant	Manatee	367.3	3054.2	24.9	-28.4	139	37.8	23,146	555	Yes
1010017	Anclote Power Plant	Pasco	327.4	3120.7	-15.0	38.1	339	40.9	13,469	618	Yes

[a] The location of the Progress Energy Bartow plant in UTM Coordinates: East 342.4 km; North 3082.6 km

[b] Based on the North Carolina Screening Threshold method, a background facility is included in the modeling analysis if the facility is within the screening area and its emission rate is greater than the product of "Distance x 20".

[c] The "Modeling Area" for the project is estimated to be 10.0 km. Pollutant concentrations were predicted in this area.

[d] The "Screening Area" is the area beyond the modeling area in which background sources were considered for modeling and extended out to 40 km from the plant.

TABLE 18-4
SUMMARY OF MAXIMUM MEASURED PM10, SO2, AND NO_2 CONCENTRATIONS OBSERVED FROM REPRESENTATIVE MONITORING STATIONS, 2004 THROUGH 2005 FOR THE BARTOW POWER PLANT PROJECT

			Measurement Period			3-Hour		24-Hour		Annual
AIRS No.	County	Location	Year	Months	Units	Highest	2nd Highest	Highest	2nd Highest	Average
PM_{10}		**Florida AAQS**			**µg/m³**	**NA**	**NA**	**NA**	**150**	**50**
12-103-0012	Pinellas	St. Petersburg	2005	Jan-Dec	µg/m³	NA	NA	55	54	23.3
			2004	Jan-Dec	µg/m³	NA	NA	133	80	29.4
12-103-0018	Pinellas	St. Petersburg	2005	Jan-Dec	µg/m³	NA	NA	30	27	16.2
			2004	Jan-Dec	µg/m³	NA	NA	34	30	18.5
Sulfur dioxide		**Florida AAQS**			**ppm**	**NA**	**0.5**	**NA**	**0.1**	**0.02**
12-103-3002	Pinellas	Pinellas Park	2005	Jan-Dec	ppm	0.041	0.038	0.014	0.013	0.0020
			2004	Jan-Dec	ppm	0.036	0.034	0.012	0.010	0.0019
			2005	Jan-Dec	µg/m³	107	99	37	34	5
			2004	Jan-Dec	µg/m³	94	89	31	26	5
12-103-0018	Pinellas	St. Petersburg	2005	Jan-Dec	ppm	0.075	0.059	0.032	0.024	0.0031
			2004	Jan-Dec	ppm	0.103	0.102	0.036	0.033	0.0045
			2005	Jan-Dec	µg/m³	196	154	84	63	8
			2004	Jan-Dec	µg/m³	269	267	94	86	12
Nitrogen dioxide		**Florida AAQS**				**NA**	**NA**	**NA**	**NA**	**0.05**
12-103-0018	Pinellas	St. Petersburg	2005	Jan-Dec	ppm	NA	NA	NA	NA	0.0082
			2004	Jan-Dec	ppm	NA	NA	NA	NA	0.0090
			2005	Jan-Dec	µg/m³	NA	NA	NA	NA	15
			2004	Jan-Dec	µg/m³	NA	NA	NA	NA	17

Note: NA = not applicable.
AAQS = ambient air quality standard.

Source:EPA Aerametric Information Retrieval System, Air Quality Subsystem, Quick Look Reports, Florida: 2004 and 2005.

TABLE 18-5
SUMMARY OF MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR THE PROJECT PHASE 2 WITH AAQS SOURCES COMPARED TO THE AAQS

			Maximum Predicted Concentration (ug/m^3)			Time Period	AAQS
Pollutant	Averaging Time	Rank	Modeled Sources [a]	Background [c]	Total	(YYMMDDHH)	(ug/m^3)
PM_{10}	Annual	Highest	2.14	29.4	31.5	1123124	50
			2.09	29.4	31.5	2123124	
			1.81	29.4	31.2	3123124	
			1.85	29.4	31.2	4123124	
			2.23	29.4	31.6	5123124	
	24-Hour	HSH	18.2	80	98.2	1110524	150
			17.6	80	97.6	2030124	
			19.0	80	99.0	3110924	
			27.4	80	107.4	4092524	
			18.8	80	98.8	5071024	
SO_2	Annual	Highest	21.1	5	26.1	1123124	60
			23.5	5	28.5	2123124	
			21.0	5	26.0	3123124	
			21.0	5	26.0	4123124	
			19.2	5	24.2	5123124	
	24-Hour	HSH	124	86	210	1022324	260
			128	86	214	2092524	
			111	86	197	3083024	
			137	86	223	4050924	
			116	86	202	5031524	
	3-Hour	HSH	464	267	731	1072809	1,300
			409	267	676	2021824	
			456	267	723	3060509	
			405	267	672	4051321	
			364	267	631	5033009	
NO_2	Annual	Highest [b]	7.7	17	24.7	1123124	100
			7.7	17	24.7	2123124	
			6.6	17	23.6	3123124	
			7.0	17	24.0	4123124	
			7.8	17	24.8	5123124	

Note: NA= not applicable
HSH= highest, second highest

[a] Phase 2 includes four CTs operating in combined cycle mode and one CT operating in simple cycle mode, with five gas-fired gas heaters and an auxilliary boiler. All CTs are oil-fired.

[b] NO_2 concentration based on NO_x to NO_2 conversion rate of 75%.

[c] Background concentrations are concentrations estimated for sources not explicitly modeled.
Based on air monitoring data collected by the FDEP in Pinellas County from 2004 to 2005. For annual averaging period, the highest measured concentration was used. For the short-term averaging periods, the overall second-highest concentration was used.

TABLE 18-6
SUMMARY OF MAXIMUM POLLUTANT CONCENTRATIONS PREDICTED FOR THE PROJECT PHASE 2 WITH PSD SOURCES COMPARED TO THE EPA PSD CLASS II INCREMENTS

			Maximum Predicted Concentration (ug/m^3)		Time Period	PSD Class II Increment
Pollutant	Averaging Time	Rank	Phase 2 Only	PSD Sources	(YYMMDDHH)	(ug/m^3)
PM_{10}	Annual	Highest	1.78	0.22	1123124	17
			1.70	0.22	2123124	
			1.42	0.26	3123124	
			1.49	0.26	4123124	
			1.90	0.32	5123124	
	24-Hour	HSH	18.2	14.8	1030524	30
			17.3	14.0	2040724	
			18.9	11.7	3112824	
			27.2	24.3	4090524	
			18.4	18.4	5071024	
SO_2	Annual	Highest	1.86	0.0	1123124	20
			1.77	0.0	2123124	
			1.42	0.0	3123124	
			1.56	0.0	4123124	
			1.94	0.0	5123124	
	24-Hour	HSH	25.2	27.6	1091424	91
			20.4	36.1	2111324	
			23.9	34.9	3102224	
			33.1	30.5	4011024	
			26.7	33.3	5100424	
	3-Hour	HSH	56.5	92.1	1051521	512
			66.9	83.1	2070724	
			53.4	93.3	3042221	
			81.6	85.4	4070118	
			84.2	90.3	5032712	
NO_2	Annual	Highest [b]	5.02	2.0	1123124	25
			4.75	1.5	2123124	
			3.77	1.4	3123124	
			4.18	1.6	4123124	
			5.27	2.5	5123124	

Note: NA= not applicable
HSH= highest, second highest

[a] Phase 2 includes four CTs operating in combined cycle mode and one CT operating in simple cycle mode, with five gas-fired gas heaters and an auxilliary boiler. All CTs are oil-fired.

[b] NO_2 concentration based on NO_x to NO_2 conversion rate of 75%.

TABLE A-1

DETAILED STACK, OPERATING, AND PM_{10} EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility	Facility Name		AERMOD	UTM Location		Stack Parameters								PM_{10} Emission		PSD	Modeled in	
				X	Y	Height		Diameter		Temperature		Velocity		Rate		Source?		PSD
ID	Emission Unit Description	EU ID	ID Name	(m)	(m)	ft	m	ft	m	°F	K	ft/s	m/s	lb/hr	g/s	(EXP/CON)	AAQS	Class II
1030117	PINELLAS CO. RESOURCE RECOVERY FACILITY																	
	Municipal Ewaste Combustor Unit 1	1	PNRRF1	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	14.4	1.81	CON	Yes	Yes
	Municipal Ewaste Combustor Unit 2	2	PNRRF2	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	14.4	1.81	CON	Yes	Yes
	Municipal Ewaste Combustor Unit 3	3	PNRRF3	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	14.4	1.81	CON	Yes	Yes
	Municipal Ewaste Combustor Units 1 - 3	1 - 3	PNRRF13	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	43.2	5.44	CON	Yes	Yes
1030012	Progress Energy Florida - Higgins																	
	FFFSG-SG 1 (Phase II, Acid Rain Unit)	1	FPCHIG1	336,500	3,098,400	174	53.04	12.5	3.81	310	428	27.0	8.23	54.8	6.90	NO	Yes	No
	FFFSG-SG 2 (Phase II, Acid Rain Unit)	2	FPCHIG2	336,500	3,098,400	174	53.04	12.5	3.81	310	428	27.0	8.23	52.3	6.59	NO	Yes	No
	FFFSG-SG 3 (Phase II, Acid Rain Unit)	3	FPCHIG3	336,500	3,098,400	174	53.04	12.5	3.81	310	428	27.0	8.23	54.8	6.90	NO	Yes	No
	FFFSG-SG 1- 3 (Phase II, Acid Rain Units)	1 - 3	FPCHIG13	336,500	3,098,400	174	53.04	12.5	3.81	310	428	27.0	8.23	161.9	20.40	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 1	4	FPCHIG4	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	20.16	2.54	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 2	5	FPCHIG5	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	20.16	2.54	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 3	6	FPCHIG6	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	22.47	2.83	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 4	7	FPCHIG7	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	22.47	2.83	NO	Yes	No
	Combustion Turbine Peaking Units - CTP 1 - 4	4 - 7	FPCHIG47	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	85.3	10.74	NO	Yes	No
0570038	TECO, Hookers Point					NOTE: ORIGINAL STACK PARAMETERS DO NOT MATCH NOX INVENTORY DATA- USED NOX PARAMETERS												
	Boiler #1	1	TECOHK1	358,000	3,091,000	280	85.3	11.2	3.4	346	448	74.4	22.7	-37.3	-4.70	EXP	No	Yes
	Boiler #2	2	TECOHK2	358,000	3,091,000	280	85.3	11.2	3.4	346	448	74.4	22.7	-37.3	-4.70	EXP	No	Yes
	Boiler #5	5	TECOHK5	358,000	3,091,000	280	85.3	11.2	3.4	346	448	74.4	22.7	-76.3	-9.61	EXP	No	Yes
	Boilers #1, #2, & #5	1, 2, 5	TECOHK15	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-150.9	-19.0	EXP	No	Yes
	Boiler #3	3	TECOHK3	358,000	3,091,000	280	85.3	11.2	3.4	346	448	74.4	22.7	-51.4	-6.48	EXP	No	Yes
	Boiler #4	4	TECOHK4	358,000	3,091,000	280	85.3	11.2	3.4	346	448	74.4	22.7	-51.4	-6.48	EXP	No	Yes
	Bolers #3 & #4	3 - 4	TECOHK34	358,000	3,091,000	280	85.3	12.0	3.66	341	445	62.7	19.1	-102.8	-13.0	EXP	No	Yes
						280	85.3	11.2	3.4	346	448	74.4	22.7					
	Boiler #6	6	TECOHK6	358,000	3,091,000	280	85.3	9.4	2.87	329	438	75.2	22.9	-97.3	-12.26	EXP	No	Yes
	30 Caterpillar XQ2000 Power Modules	8-37	TECOHKPM	358,000	3,091,000	10	3.0	0.7	0.2	808	704	681.0	207.6	7.5	0.95	CON	Yes	Yes
0570040	TECO, Bayside Power Station																	
	Unit #1 125 MW Coal Fired Boiler with Steam Generator	1	TECOBA1	360,100	3,087,500	315	96.01	12.1	3.69	302	423	92	28.04	-126.0	-15.88	EXP	No	Yes
	Unit #2 125 MW Coal Fired Boiler with Steam Generator	2	TECOBA2	360,100	3,087,500	315	96.01	12.1	3.69	302	423	92	28.04	-126.0	-15.88	EXP	No	Yes
	Unit #3 180 MW Coal Fired Boiler with Steam Generator	3	TECOBA3	360,100	3,087,500	315	96.01	12.1	3.69	302	423	92	28.04	-160.0	-20.16	EXP	No	Yes
	Unit #4 188 MW Coal Fired Boiler with Steam Generator	4	TECOBA4	360,100	3,087,500	315	96.01	12.1	3.69	302	423	92	28.04	-188.0	-23.69	EXP	No	Yes
	Units #1 - #4 Coal Fired Boilers with Steam Generators	1 - 4	TECOBA14	360,100	3,087,500	315	96.0	12.1	3.69	302	423	92.0	28.0	-600.0	-75.60	EXP	No	Yes
						315	96.01	12.1	3.69	302	423	92	28.04					
	Unit #5 239 MW Coal Fired Boiler with Steam Generator	5	TECOBA5	360,100	3,087,500	315	96.01	14.6	4.45	303	424	76.0	23.2	-228.0	-28.73	EXP	No	Yes
						315	96.01	12.1	3.69	302	423	92	28.04					
	Unit #6 414 MW Coal Fired Boiler with Steam Generator	6	TECOBA6	360,100	3,087,500	315	96.0	17.6	5.36	320	433	81.0	24.7	-380.0	-47.88	EXP	No	Yes
	14 MW Gas-Fired Turbine	7	TECOBA7	360,100	3,087,500	35	10.67	11	3.35	1010	816	92.6	28.22	-122.0	-15.37	EXP	No	Yes
	Economizer Ash Silo	9	TECOBA9	360,100	3,087,500	72	21.95	0.7	0.21	350	450	35	10.67	-0.14	-0.02	EXP	No	Yes
	Flyash Silo No. 1 For Units 5 & 6	10	TECOBA10	360,100	3,087,500	107	32.61	1.0	0.30	350	450	99	30.18	-1.20	-0.15	EXP	No	Yes
	Fly Ash Silo No. 2 Units 1-4	11	TECOBA11	360,100	3,087,500	104	31.70	2.0	0.61	350	450	59	17.98	-2.90	-0.37	EXP	No	Yes
		7-11	TECOBA7	360,100	3,087,500	35	10.67	11	3.35	1010	816	92.6	28.22	-126.2	-15.91	EXP	No	Yes
	Unit 1 Coal Bunker W/Roto-Clone	13	TECOBA13	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Unit 2 Coal Bunker W/Roto-Clone	14	TECOBA14	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Unit 3 Coal Bunker W/Roto-Clone	15	TECOBA15	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Unit 4 Coal Bunker W/Roto-Clone	16	TECOBA16	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Unit 5 Coal Bunker W/Roto-Clone	17	TECOBA17	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Unit 6 Coal Bunker W/Roto-Clone	18	TECOBA18	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70	21.34	-0.19	-0.02	EXP	No	Yes
	Units 1 - 6 Coal Bunkers W/Roto-Clones	1 - 6	TECOBAX	360,100	3,087,500	175	53.34	1.7	0.52	78	299	70.0	21.34	-1.1	-0.14	EXP	No	Yes
	Bayside Unit 1A – 170 MW combined cycle gas turbine	20	TECOBA20	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Unit 1B – 170 MW combined cycle gas turbine	21	TECOBA21	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Unit 1C – 170 MW combined cycle gas turbine	22	TECOBA22	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Unit 2A – 170 MW combined cycle gas turbine	23	TECOBA23	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Unit 2B – 170 MW combined cycle gas turbine	24	TECOBA24	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Unit 2C – 170 MW combined cycle gas turbine	25	TECOBA25	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes

TABLE A-1
DETAILED STACK, OPERATING, AND PM_{10} EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	PM_{10} Emission Rate lb/hr	PM_{10} Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
	Bayside Unit 2D – 170 MW combined cycle gas turbine	26	TECOBA26	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	11.5	1.45	CON	Yes	Yes
	Bayside Units 1A,B,C & 2A,B,C,D – 170 MW combined cycle gas turbines	1 - 6	TECOBA2X	360,100	3,087,500	150	45.72	19.0	5.79	220	378	60.5	18.44	80.5	10.14	CON	Yes	Yes
0570094	Mosaic - Big Bend Terminal																	
	Shipping Terminal Incoming/Transfer Point #1	1	MOSBBT1	361,000	3,076,200	36	11.0	1.5	0.46	95	308	43.0	13.1	1.2	0.15	CON	Yes	Yes
	Shipping Terminal Outgoing Transfer Point #2	2	MOSBBT2	361,000	3,076,200	25	7.6	1.3	0.40	95	308	34.0	10.4	0.7	0.09	CON	Yes	Yes
	Shipping Terminal Outgoing Transfer Point #3	3	MOSBBT3	361,000	3,076,200	25	7.6	1.3	0.40	95	308	34.0	10.4	0.7	0.09	CON	Yes	Yes
	Shipping Terminal Outgoing Transfer Point #2 & #3	2 - 3	MOSBBT23	361,000	3,076,200	25	7.6	1.3	0.40	95	308	34.0	10.4	1.4	0.18	CON	Yes	Yes
	Shipping Terminal Gantry and Shiploading	4	MOSBBT4	361,000	3,076,200	30	9.1	2.2	0.67	95	308	34.0	10.4	5.1	0.65	CON	Yes	Yes
0570127	Mckay Bay Refuse-To-Energy Facility																	
	Unit #1 - The West Most Unit.	1	MBREF1	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	7.0	0.88	CON	Yes	Yes
	Unit #2 - Second West Most Unit. Burns Municipal Waste Only.	2	MBREF2	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	7.0	0.88	CON	Yes	Yes
	Unit #3 - 3rd Westmost Unit - Burns Municipal Waste.	3	MBREF3	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	7.0	0.88	CON	Yes	Yes
	Unit #4 - East Most Unit. Burns Municipal Waste.	4	MBREF4	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	7.0	0.88	CON	Yes	Yes
	Unit #1 - #4	1 - 4	MBREF14	360,200	3,092,210	160	48.77	5.7	1.74	450	505	41.0	12.50	28.0	3.53	CON	Yes	Yes
	Flyash Silo In Refuse To Energy Facility	5	MBREF5	360,200	3,092,210	57	17.4	2.0	0.61	200	366	11.0	3.4	0.4	0.05	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 1	103	MBREF103	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	2.8	0.35	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 2	104	MBREF104	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	2.8	0.35	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 3	105	MBREF105	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	2.76	0.35	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 4	106	MBREF106	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	2.76	0.35	CON	Yes	Yes
	Municipal Waste Combustors & Auxiliary Burners - Unit Nos. 1 - 4	103 - 106	MBREF10X	360,200	3,092,210	201	61.26	4.2	1.28	289	416	73.3	22.34	11.0	1.39	CON	Yes	Yes
0570008	Mosaic Riverview Facility																	
	DAP Manufacturing Plant	7	MOSRIV7	362,900	3,082,500	126	38.4	8.0	2.44	104	313	34.5	10.5	12.9	1.62	CON	Yes	Yes
	No. 3 MAP Plant	22	MOSRIV22	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	3.3	0.42	CON	Yes	Yes
	No. 4 MAP Plant	23	MOSRIV23	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	3.3	0.42	CON	Yes	Yes
	South Cooler	24	MOSRIV24	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	3.3	0.42	CON	Yes	Yes
	Nos. 3 - 4 MAP Plants & South Cooler	22 - 24	MOSRIV2X	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	10.0	1.26	CON	Yes	Yes
	West Bag Filter	51	MOSRIV51	362,900	3,082,500	30	9.1	3.5	1.07	80	300	57.2	17.4	1.2	0.15	CON	Yes	Yes
	South Baghouse	52	MOSRIV52	362,900	3,082,500	50	15.2	1.5	0.46	80	300	42.4	12.9	1.2	0.15	CON	Yes	Yes
	Vessel Loading System -- Tower Baghouse Exhaust	53	MOSRIV53	362,900	3,082,500	30	9.1	2.5	0.76	80	300	40.7	12.4	0.8	0.10	CON	Yes	Yes
	No. 5 DAP Plant	55	MOSRIV55	362,900	3,082,500	133	40.5	7.0	2.13	110	316	67.6	20.6	12.8	1.61	CON	Yes	Yes
	Building #6 Belt to Conveyor #7 Transfer Point	58	MOSRIV58	362,900	3,082,500	30	9.1	1.2	0.35	80	300	57.2	17.4	0.6	0.08	CON	Yes	Yes
	Conveyor #7 to Conveyor #8 Transfer Point with Baghouse	59	MOSRIV59	362,900	3,082,500	45	13.7	1.2	0.35	80	300	57.2	17.4	0.6	0.08	CON	Yes	Yes
	Conveyor #8 to Conveyor #9 Transfer Point with Baghouse	60	MOSRIV60	362,900	3,082,500	75	22.9	1.6	0.48	80	300	59.5	18.1	1.2	0.15	CON	Yes	Yes
	Animal Feed Ingredient (AFI) Plant No. 1	78	MOSRIV78	362,900	3,082,500	136	41.5	6.0	1.83	150	339	64.5	19.7	8.0	1.01	CON	Yes	Yes
	Diatomaceous Earth Silo	79	MOSRIV79	362,900	3,082,500	64	19.5	1.5	0.46	90	305	5.7	1.7	0.1	0.01	CON	Yes	Yes
	Limestone Silo	80	MOSRIV80	362,900	3,082,500	85	25.9	1.5	0.46	90	305	33.0	10.1	0.3	0.04	CON	Yes	Yes
	Animal Feed Plant Loadout System	81	MOSRIV81	362,900	3,082,500	30	9.1	3.0	0.91	90	305	54.5	16.6	2.1	0.26	CON	Yes	Yes
	Animal Feed Ingredient Plant No. 2	103	MOSRIV103	362,900	3,082,500	145	44.2	7.0	2.13	150	339	66.4	20.2	13.1	1.66	CON	Yes	Yes
	South Baghouse	52 Plus	MOSRIV52	362,900	3,082,500	50	15.2	1.5	0.46	80	300	42.4	12.9	8.0	1.01	CON	Yes	Yes
	No. 5 DAP Plant	55	MOSRIV55	362,900	3,082,500	133	40.5	7.0	2.13	110	316	67.6	20.6	12.8	1.61	CON	Yes	Yes
	Animal Feed Ingredient (AFI) Plant No. 1	78	MOSRIV78	362,900	3,082,500	136	41.5	6.0	1.83	150	339	64.5	19.7	8.0	1.01	CON	Yes	Yes
	Animal Feed Ingredient Plant No. 2	103	MOSRIV1X	362,900	3,082,500	145	44.2	7.0	2.13	150	339	66.4	20.2	13.1	1.66	CON	Yes	Yes
	Ammonia Plant		AMMPLTB	362,900	3,082,500	60	18.3	8.3	2.53	600	589	22.7	6.9	-18.4	-2.32	EXP	No	Yes
	Sodium Silicofluoride/Sodium Fluoride Plant		SSFSFPB	362,900	3,082,500	28	8.5	2.5	0.76	95	308	11.6	3.5	-6.1	-0.76	EXP	No	Yes
	No. 2 and No. 3 Rock Silo Bag Filter		NO23RSB	362,900	3,082,500	93	28.3	1.1	0.34	91	306	48.8	14.9	-0.9	-0.11	EXP	No	Yes
	Nos. 6, 7, and 8 Rock Mills		NO678RB	362,900	3,082,500	95	29.0	2.0	0.61	91	306	55.5	16.9	-8.6	-1.08	EXP	No	Yes
	No. 10 KVS Mill		10KVSMB	362,900	3,082,500	87	26.5	1.7	0.52	118	321	59.8	18.2	-4.4	-0.55	EXP	No	Yes
	No. 11 KVS Mill		11KVSMB	362,900	3,082,500	70	21.3	1.6	0.49	126	325	63.6	19.4	-6.9	-0.87	EXP	No	Yes
	No. 12 KVS Mill		12KVSMB	362,900	3,082,500	71	21.6	1.6	0.49	135	330	68.5	20.9	-2.9	-0.37	EXP	No	Yes
	No. 2 Air Slide North Bag Filter		2ASNBFB	362,900	3,082,500	85	25.9	1.0	0.30	97	309	47.7	14.6	-1.2	-0.15	EXP	No	Yes
	No. 2 Air Slide South Bag Filter		2ASSBFB	362,900	3,082,500	96	29.3	0.9	0.27	115	319	72.8	22.2	-0.4	-0.05	EXP	No	Yes
	No. 3 Air Slide North Bag Filter		3ASNBFB	362,900	3,082,500	82	25.0	1.2	0.37	113	318	16.1	4.9	-0.2	-0.03	EXP	No	Yes
	No. 3 Air Slide Center Bag Filter		3ARCBFB	362,900	3,082,500	115	35.1	1.2	0.37	118	321	25.8	7.9	-1.0	-0.12	EXP	No	Yes

TABLE A-1

DETAILED STACK, OPERATING, AND PM_{10} EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

				UTM Location		Stack Parameters								PM_{10} Emission		PSD	Modeled in	
Facility	Facility Name		AERMOD	X	Y	Height		Diameter		Temperature		Velocity		Rate		Source?		PSD
ID	Emission Unit Description	EU ID	ID Name	(m)	(m)	ft	m	ft	m	°F	K	ft/s	m/s	lb/hr	g/s	(EXP/CON)	AAQS	Class II
	No. 3 Air Slide South Bag Filter		3ASSBFB	362,900	3,082,500	100	30.5	1.2	0.37	117	320	16.5	5.0	-0.8	-0.11	EXP	No	Yes
	No. 3 Air Slide Bin Bag Filter		3ASBBFB	362,900	3,082,500	108	32.9	1.2	0.37	122	323	23.3	7.1	-1.1	-0.14	EXP	No	Yes
	No. 2 Phosphoric Acid System		PASNO2B	362,900	3,082,500	110	33.5	4.0	1.22	145	336	43.3	13.2	-14.8	-1.86	EXP	No	Yes
	No. 3 Phosphoric Acid System		PASNO3B	362,900	3,082,500	93	28.3	4.0	1.22	118	321	23.5	7.2	-9.2	-1.16	EXP	No	Yes
	No. 1 Horizontal Filter Scrubber		1HZFSB	362,900	3,082,500	59	18.0	4.8	1.45	86	303	35.5	10.8	-6.5	-0.82	EXP	No	Yes
	No. 2 Horizontal Filter Scrubber		2HZFSB	362,900	3,082,500	51	15.5	4.0	1.22	93	307	51.9	15.8	-10.4	-1.31	EXP	No	Yes
	No. 2 Horizontal Filter Vacuum System		2HZFVSB	362,900	3,082,500	4.5	1.4	1.1	0.34	153	340	16.8	5.1	0.0	0.00	EXP	No	Yes
	No. 3 Horizontal Filter Vacuum System		3HZFVSB	362,900	3,082,500	4.5	1.4	1.5	0.46	126	325	16.3	5.0	-0.7	-0.08	EXP	No	Yes
	No. 7 Oil-Fired Concentrator		7OFCONB	362,900	3,082,500	78	23.8	6.0	1.83	165	347	17.2	5.2	-12.5	-1.58	EXP	No	Yes
	No. 8 Oil-Fired Concentrator		8OFCONB	362,900	3,082,500	78	23.8	6.0	1.83	159	344	16.7	5.1	-16.8	-2.12	EXP	No	Yes
	GTSP Bag Filter		GTSPBFB	362,900	3,082,500	88	26.8	1.3	0.40	153	340	26.6	8.1	-0.5	-0.06	EXP	No	Yes
	GTSP Plant		GTSPAPB	362,900	3,082,500	126	38.4	8.0	2.44	129	327	34.9	10.7	-19.1	-2.41	EXP	No	Yes
	No. 5 and No. 9 Mills Bag Filter		RKML59B	362,900	3,082,500	66	20.1	2.0	0.61	115	319	58.3	17.8	-12.4	-1.56	EXP	No	Yes
	No. 3 Triple Reactor Belt		3TRIPLB	362,900	3,082,500	65	19.8	4.0	1.22	77	298	48.4	14.7	-11.8	-1.49	EXP	No	Yes
	No. 4 Triple Reactor Belt		4TRIPLB	362,900	3,082,500	65	19.8	4.0	1.22	84	302	50.9	15.5	-8.6	-1.08	EXP	No	Yes
	No. 3 Continuous Triple Dryer		3CONTDB	362,900	3,082,500	68	20.7	3.5	1.07	115	319	45.8	14.0	-18.2	-2.29	EXP	No	Yes
	No. 4 Continuous Triple Dryer		4CONTDB	362,900	3,082,500	68	20.7	3.5	1.07	134	330	61.8	18.8	-11.8	-1.49	EXP	No	Yes
	Nos. 2 & 4 Sizing Units		24SIZUB	362,900	3,082,500	74	22.6	4.0	1.22	73	296	29.7	9.1	-9.7	-1.22	EXP	No	Yes
	Normal Superphosphate		NORMSPB	362,900	3,082,500	73	22.3	2.5	0.76	104	313	53.1	16.2	-2.3	-0.29	EXP	No	Yes
	GTSP Plant		GTSPAPB	362,900	3,082,500	126	38.4	8.0	2.44	129	327	34.9	10.7	-218.1	-27.5	EXP	No	Yes
	No. 1 Ammonium Phosphate Plant		1AMMPPB	362,900	3,082,500	90	27.4	3.5	1.07	141	334	60.0	18.3	-11.7	-1.47	EXP	No	Yes
	No. 2 Ammonium Phosphate Plant		2AMMPPB	362,900	3,082,500	90	27.4	3.5	1.07	141	334	60.0	18.3	-16.1	-2.03	EXP	No	Yes
	No. 3 Ammonium Phosphate Plant		3AMMPPB	362,900	3,082,500	90	27.4	3.5	1.07	141	334	60.0	18.3	-12.9	-1.63	EXP	No	Yes
	No. 4 Ammonium Phosphate Plant		4AMMPPB	362,900	3,082,500	90	27.4	3.5	1.07	141	334	60.0	18.3	-18.9	-2.38	EXP	No	Yes
	Nos. 1 - 4 Ammonium Phosphate Plants		AMMPPB	362,900	3,082,500	90	27.43	3.5	1.07	141	334	60.0	18.29	-59.6	-7.51	EXP	No	Yes
	North Ammonium Phosphate Cooler		NAMMPCB	362,900	3,082,500	55	16.8	4.3	1.31	144	335	69.7	21.2	-64.8	-8.16	EXP	No	Yes
	South Ammonium Phosphate Cooler		SAMMPCB	362,900	3,082,500	55	16.8	4.3	1.31	144	335	69.7	21.2	-67.3	-8.48	EXP	No	Yes
	North & South Ammonium Phosphate Coolers		AMMPCB	362,900	3,082,500	55	16.8	4.3	1.31	144	335	69.7	21.2	-132.1	-16.64	EXP	No	Yes
0570039	TECO - Big Bend Station																	
	Unit #1 Coal Fired Boiler w/ ESP	1	TECOBB1	361,900	3,075,000	490	149.35	24.0	7.3	294	419	115.9	35.3	121.1	15.26	NO	Yes	No
	Unit #2 Riley-Stoker Coal Boiler w/ Esp	2	TECOBB2	361,900	3,075,000	490	149.35	24.0	7.3	125	325	87.6	26.7	119.9	15.11	NO	Yes	No
	Unit #3 Riley-Stoker Coal Boiler w/ ESP	3	TECOBB3	361,900	3,075,000	499	152.10	24.0	7.3	279	410	47.0	14.3	123.5	15.56	CON	Yes	Yes
	Unit #4 Coal Boiler W/ Belco ESP	4	TECOBB4	361,900	3,075,000	499	152.10	24.0	7.3	156	342	59.0	18.0	43.3	5.46	CON	Yes	Yes
	Combustion Turbine #2 - No. 2 Fuel Oil	5	TECOBB5	361,900	3,075,000	75	22.86	14.0	4.3	928	771	61.0	18.6	33.0	4.16	NO	Yes	No
	Combustion Turbine #3 - No. 2 Fuel Oil	6	TECOBB6	361,900	3,075,000	75	22.86	14.0	4.3	928	771	61.0	18.6	33.0	4.16	NO	Yes	No
	Combustion Turbine #2 & #3 - No. 2 Fuel Oil	5 - 6	TECOBB56	361,900	3,075,000	75	22.9	14.0	4.27	928	771	61.0	18.6	66.0	8.32	NO	Yes	No
	Combustion Turbine #1 - No. 2 Fuel Oil	7	TECOBB7	361,900	3,075,000	35	10.67	11.0	3.4	1010	816	91.9	28.0	33.0	4.16	NO	Yes	No
	Fly Ash Silo No. 1 Baghouse	8	TECOBB8	361,900	3,075,000	102	31.09	2.5	0.8	250	394	52.0	15.8	5.16	0.650	NO	Yes	No
	Fly Ash Silo No. 2 Baghouse	9	TECOBB9	361,900	3,075,000	113	34.44	0.9	0.3	250	394	52.0	15.8	5.16	0.650	NO	Yes	No
	Fly Ash Silo No. 1 & 2 Baghouse	8-9	TECOBB89	361,900	3,075,000	113	34.44	0.9	0.3	250	394	52.0	15.8	10.32	1.300	NO	Yes	No
	Limestone Silo A W/ 2 Baghouses	12	TECOBB12	361,900	3,075,000	101	30.78	0.5	0.2	150	339	46.0	14.0	0.05	0.006	NO	Yes	No
	Limestone Silo B W/ 2 Baghouses	13	TECOBB13	361,900	3,075,000	101	30.78	0.3	0.2	150	339	46.0	14.0	0.05	0.006	NO	Yes	No
	Limestone Silos A & B W/ 2 Baghouses	12 - 13	TECOBBSB	361,900	3,075,000	101	30.8	0.5	0.15	150	339	46.0	14.0	0.1	0.01	NO	Yes	No
	Flyash Silo For Unit #4	14	TECOBB14	361,900	3,075,000	139	42.37	1.6	0.5	140	333	59.0	18.0	0.20	0.025	NO	Yes	No
	Unit 1 Coal Bunker W/Roto-Clone	15	TECOBB15	361,900	3,075,000	179	54.56	1.7	0.5	78	299	69.0	21.0	0.48	0.060	NO	Yes	No
	Unit 2 Coal Bunker W/Roto-Clone	16	TECOBB16	361,900	3,075,000	179	54.56	1.7	0.5	78	299	69.0	21.0	0.48	0.060	NO	Yes	No
	Unit 3 Coal Bunker W/Roto-Clone	17	TECOBB17	361,900	3,075,000	179	54.56	1.7	0.5	78	299	69.0	21.0	0.48	0.060	NO	Yes	No
	Units 1 - 3 Coal Bunkers W/Roto-Clones	15 - 17	TECOBBCB	361,900	3,075,000	179	54.6	1.7	0.52	78	299	69.0	21.0	1.4	0.18	NO	Yes	No
0570261	Hillsborough Cty. RRF																	
	Unit #1 - The West Most Unit.	1	HCRRF1	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	7.0	0.88	CON	Yes	Yes
	Unit #2 - Second West Most Unit. Burns Municipal Waste Only.	2	HCRRF2	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	7.0	0.88	CON	Yes	Yes
	Unit #3 - 3rd Westmost Unit - Burns Municipal Waste.	3	HCRRF3	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	7.0	0.88	CON	Yes	Yes
	Units #1 - #3	1 - 3	HCRRF1	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	21.0	2.65	CON	Yes	Yes
	IMC Agrico (Pierce)																	
	PSD Expanding source	1	1AGRI	404,100	3,079,000	80	24.38	8	2.4	118	321	69.7	21.2	-40.0	-5.04	EXP	No	Yes

TABLE A-1

DETAILED STACK, OPERATING, AND PM_{10} EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	PM_{10} Emission Rate lb/hr	PM_{10} Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
	PSD Expanding source	2	2AGR1	404,100	3,079,000	95	28.96	5.8	1.8	770	683	48.8	14.9	-31.1	-3.92	EXP	No	Yes
	PSD Expanding source	2	12AGR1	404,100	3,079,000	95	28.96	5.8	1.8	770	683	48.8	14.9	-71.1	-8.96	EXP	No	Yes
0810010	Florida Power & Light - Manatee																	
	Generator Unit 1	1	FPLMAN1	367,250	3,054,150	499	152.1	26.2	8.0	325	436	68.7	20.9	865	108.99	NO	Yes	No
	Generator Unit 2	2	FPLMAN2	367,250	3,054,150	499	152.1	26.2	8.0	325	436	68.7	20.9	865	108.99	NO	Yes	No
	Generator Units 1 & 2	1 - 2	FPLMAN12	367,250	3,054,150	499	152.1	26.2	7.99	325	436	68.7	20.9	1730.0	217.98	NO	Yes	No
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3A	5	FPLMAN5	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	17.2	2.17	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3B	6	FPLMAN6	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	17.2	2.17	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3C	7	FPLMAN7	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	17.2	2.17	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3D	8	FPLMAN8	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	17.2	2.17	CON	Yes	Yes
	Gas Turbines (nominal 170 MW) with HRSG- Units No.3A,B,C,D	5 - 8	FPLMAN58	367,250	3,054,150	120	36.58	19.0	5.79	202	368	59.0	17.98	68.8	8.67	CON	Yes	Yes
	Stauffer Tarpon Springs																	
	Boiler	1	STAUFF1	325,600	3,116,700	24	7.3	3.0	0.9	376	464	10.6	3.2	-9.80	-1.23	EXP	No	Yes
	Rotary Kiln	2	STAUFF2	325,600	3,116,700	161	49.1	3.9	1.2	143	335	11.8	3.6	-92.70	-11.68	EXP	No	Yes
	Furnace	3	STAUFF3	325,600	3,116,700	84	25.6	3.0	0.91	120	322	22.9	7.0	-1.44	-0.18	EXP	No	Yes
	All units	1-3	STAUFF13	325,600	3,116,700	161	49.1	3.9	1.2	143	335	11.8	3.6	-103.94	-13.10	EXP	No	Yes
1010017	Progress Energy-Anclote Power Plant																	
	Steam Turbine Gen. Anclote Unit No.1	1	FPCANC1	327,410	3,120,680	499	152.10	24	7.3	320	433	62.0	18.9	507.3	63.92	NO	Yes	No
	Steam Turbine Gen. Anclote Unit No.2	2	FPCANC2	327,410	3,120,680	499	152.10	24	7.3	320	433	62.0	18.9	495.7	62.46	NO	Yes	No
	Steam Turbine Gens. Anclote Unit Nos. 1 & 2	1 - 2	FPCANC12	327,410	3,120,680	499	152.1	24.0	7.32	320	433	62.0	18.9	1003.0	126.38	NO	Yes	No

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Baseline Source, does not affect PSD increment.

TABLE A-2
DETAILED STACK, OPERATING, AND SO_2 EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate lb/hr	SO_2 Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
0570028	National Gypsum Co.																	
	#1 Calcidyne	21	NGC21	348,830	3,082,690	42	12.8	1.1	0.34	350	450	59.2	18.1	3.4	0.4	CON	Yes	Yes
	#2 Calcidyne	22	NGC22	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	3.4	0.4	CON	Yes	Yes
	#3 Calcidyne Unit	23	NGC23	348,830	3,082,690	42	12.8	1.1	0.34	350	450	68.0	20.7	3.4	0.4	CON	Yes	Yes
	#4 Calcidyne Unit	24	NGC24	348,830	3,082,690	42	12.8	1.1	0.34	350	450	61.7	18.8	3.4	0.4	CON	Yes	Yes
	#1 - #4 Calcidyne Units	21 - 24	NGC2124	348,830	3,082,690	42	12.8	1.1	0.34	350	450	59.2	18.1	13.7	1.7	CON	Yes	Yes
	No. 5 Calcidyne Unit	28	NGC28	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.4	0.4	CON	Yes	Yes
	No. 6 Calcidyne Unit	29	NGC29	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.4	0.4	CON	Yes	Yes
	No. 7 Calcidyne Unit	30	NGC30	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.4	0.4	CON	Yes	Yes
	No. 8 Calcidyne Unit	31	NGC31	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.4	0.4	CON	Yes	Yes
	Nos. 5 - 8 Calcidyne Units	28 - 31	NGC2831	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	13.7	1.7	CON	Yes	Yes
	Wallboard Kiln No. 2	34	NGC34	348,830	3,082,690	47	14.3	2.5	0.76	309	427	67.0	20.4	0.041	0.005	CON	Yes	Yes
	Ten Deck Kiln Dryer In Board Plant No. 1	47	NGC47	348,830	3,082,690	35	10.7	2.8	0.85	300	422	64.0	19.5	0.041	0.005	CON	Yes	Yes
	No. 9 & 10 Calcidyne Units	34&47	NGC3447	348,830	3,082,690	35	10.7	2.8	0.85	300	422	64.0	19.5	0.08	0.01	CON	Yes	Yes
	Calcidyne Unit No. 9	100	NGC100	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	2.49	0.31	CON	Yes	Yes
	No. 10 Calcidyne	101	NGC101	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	2.49	0.31	CON	Yes	Yes
	No. 9 & 10 Calcidyne Units	100 - 101	NGC10X	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	4.98	0.63	CON	Yes	Yes
	Rock Dryer & Crusher	36	NGC36	348,830	3,082,690	64	19.5	3.5	1.07	185	358	38.7	11.8	0.75	0.09	CON	Yes	Yes
	Impact Mill #1	102	NGC102	348,830	3,082,690	90	27.4	3.9	1.19	200	366	44.6	13.6	0.72	0.09	CON	Yes	Yes
	Impact Mill #2	103	NGC103	348,830	3,082,690	90	27.4	3.0	0.91	200	366	75.5	23.0	0.72	0.09	CON	Yes	Yes
1030117	Pinellas Co. Board Of Co. Commissioners																	
	Municipal Waste Combustor & Auxiliary burners-Unit #1	1	PNRRF1	335,200	3,071,300	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.4	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #2	2	PNRRF2	335,200	3,071,300	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.4	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #3	3	PNRRF3	335,200	3,071,300	165	50.3	8.5	2.59	270	405	71.4	21.8	170.00	21.4	CON	Yes	Yes
	Eus 1, 2,& 3 Modeled Using PCRRF1		PNRRF13	335200	3071300	165	50.3	8.5	2.59	270	405	71.4	21.8	510.00	64.3	CON	Yes	Yes
1030013	Progress Energy Florida, Inc. - Bayboro																	
	Combustion Turbine Peaking Unit # 1	1	FPCBAY1	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	390.90	49.25	NO	Yes	No
	Combustion Turbine Peaking Unit # 2	2	FPCBAY2	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	390.90	49.25	NO	Yes	No
	Combustion Turbine Peaking Unit # 3	3	FPCBAY3	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	390.90	49.25	NO	Yes	No
	Combustion Turbine Peaking Unit # 4	4	FPCBAY4	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	390.90	49.25	NO	Yes	No
	Eus 1, 2, 3,& 4 Modeled Using FPCBAY1		FBCBAY14	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	1,563.60	197.01	NO	Yes	No
1030012	Progress Energy Florida - Higgins																	
	FFFSG-SG 1 (Phase II, Acid Rain Unit)	1	PEFHIG1	336,500	3,098,400	174	53.04	12.5	3.81	312	429	27.0	8.23	1507.0	189.9	NO	Yes	No
	FFFSG-SG 2 (Phase II, Acid Rain Unit)	2	PEFHIG2	336,500	3,098,400	174	53.04	12.5	3.81	310	428	27.0	8.23	1438.3	181.2	NO	Yes	No
	FFFSG-SG 3 (Phase II, Acid Rain Unit)	3	PEFHIG3	336,500	3,098,400	174	53.04	12.5	3.81	301	423	24.0	7.32	1507.0	189.9	NO	Yes	No
	Eus 1, 2,& 3 Modeled Using PEFHIG1		PEFHIG13	336500	3098400	174	53.04	12.5	3.81	312	429	27.0	8.23	4452.30	560.99	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 1	4	PEFHIG4	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	286.3	36.07	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 2	5	PEFHIG5	336,500	3,098,400	56	17.07	15.1	4.60	850	728	93.1	28.38	286.3	36.07	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 3	6	PEFHIG6	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	319.1	40.21	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 4	7	PEFHIG7	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	319.1	40.21	NO	Yes	No
	Eus 4,5,6,& 7 are Modeled Using PEFHIG4		PEFHIG47	336,500	3,098,400	55	16.76	15.1	4.60	850	728	93.1	28.38	1210.8	152.56	NO	Yes	No
0570038	TECO, Hookers Point																	
	Expanding Source - Boiler #1	1	TECOHK1	358,000	3,091,000	280	85.3	11.3	3.4	356	453	82.0	25.0	-327.8	-41.30	EXP	No	Yes
	Expanding Source - Boiler #2	2	TECOHK2	358,000	3,091,000	280	85.3	11.3	3.4	356	453	82.0	25.0	-327.8	-41.30	EXP	No	Yes
	Expanding Source - Boiler #5	5	TECOHK5	358,000	3,091,000	280	85.3	11.3	3.4	356	453	82.0	25.0	-671.0	-84.55	EXP	No	Yes
	Boilers #1, #2, & #5	1, 2, 5	TECOHK15	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-1,326.6	-167.2	EXP	No	Yes
	Expanding Source - Boiler #3	3	TECOHK3	358,000	3,091,000	280	85.3	12.0	3.7	341	445	62.7	19.1	-452.1	-56.96	EXP	No	Yes
	Expanding Source - Boiler #4	4	TECOHK4	358,000	3,091,000	280	85.3	12.0	3.7	341	445	62.7	19.1	-452.1	-56.96	EXP	No	Yes
	Bolers #3 & #4	3 - 4	TECOHK34	358,000	3,091,000	280	85.3	12.0	3.66	341	445	62.7	19.1	-904.2	-113.9	EXP	No	Yes
	Expanding Source - Boiler #6	6	TECOHK6	358,000	3,091,000	280	85.3	9.4	2.9	329	438	75.2	22.9	-855.8	-107.83	EXP	No	Yes
	30 Caterpillar XQ2000 Power Modules	8-37	TECOHKPM	358,000	3,091,000	10	3.0	0.7	0.2	808	704	681.0	207.6	2.23	0.28	CON	Yes	Yes
0570040	TECO, Bayside Power Station																	
	Unit #1 125 MW Coal Fired Boiler with Steam Generator	1	TECOBA1	360,100	3,087,500	315	96.01	10	3.05	289	416	94	28.65	-3,017.0	-380.14	EXP	No	Yes
	Unit #2 125 MW Coal Fired Boiler with Steam Generator	2	TECOBA2	360,100	3,087,500	315	96.01	10	3.05	298	421	101	30.78	-3,017.0	-380.14	EXP	No	Yes

TABLE A-2

DETAILED STACK, OPERATING, AND SO_2 EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	SO_2 Emission Rate lb/hr	SO_2 Emission Rate g/s	PSD Source? (EXP/CON)	Modeled In AAQS	Modeled In PSD Class II
	Unit #3 180 MW Coal Fired Boiler with Steam Generator	3	TECOBA3	360,100	3,087,500	315	96.01	10.6	3.23	296	420	126	38.40	-3,838.0	-483.59	EXP	No	Yes
	Unit #4 188 MW Coal Fired Boiler with Steam Generator	4	TECOBA4	360,100	3,087,500	315	96.01	10	3.05	309	427	75	22.86	-4,502.0	-567.25	EXP	No	Yes
	Units #1 - #4 Coal Fired Boilers with Steam Generators	1 - 4	TECOBA14	360,100	3,087,500	315	96.0	10.0	3.05	289	416	94.0	28.7	-14,374.0	-1,811.1	EXP	No	Yes
	Unit #5 239 MW Coal Fired Boiler with Steam Generator	5	TECOBA5	360,100	3,087,500	315	96.01	14.6	4.45	303	424	76	23.16	-5,482.0	-690.73	EXP	No	Yes
	Unit #6 414 MW Coal Fired Boiler with Steam Generator	6	TECOBA6	360,100	3,087,500	315	96.01	17.6	5.36	320	433	81	24.69	-9,115.0	-1148.49	EXP	No	Yes
	14 MW Gas-Fired Turbine	7	TECOBA7	360,100	3,087,500	35	10.67	11	3.35	1010	816	92.6	28.22	-9.2	-1.16	EXP	No	Yes
	Bayside Unit 1A – 170 MW combined cycle gas turbine	20	TECOBA20	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 1B – 170 MW combined cycle gas turbine	21	TECOBA21	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 1C – 170 MW combined cycle gas turbine	22	TECOBA22	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 2A – 170 MW combined cycle gas turbine	23	TECOBA23	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 2B – 170 MW combined cycle gas turbine	24	TECOBA24	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 2C – 170 MW combined cycle gas turbine	25	TECOBA25	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Bayside Unit 2D – 170 MW combined cycle gas turbine	26	TECOBA26	360,100	3,087,500	150	45.72	19	5.79	220	378	60.5	18.44	10.3	1.30	CON	Yes	Yes
	Eus 20-26 are Modeled Using TECOBA20		TECOBA2X	360100	3087500	150	45.72	19	5.79	220	378	60.5	18.44	72.1	9.08	CON	Yes	Yes
0570008	Mosaic Fertilizer, LLC --Riverview																	
	NO. 7 SULFURIC ACID PLANT	4	MFR7SAP	362900	3082500	150	45.7	7.5	2.29	152	340	41.5	12.6	467.0	58.8	NO	Yes	No
	NO. 8 SULFURIC ACID PLANT	5	MFR8SAP	362900	3082500	150	45.7	8.0	2.44	165	347	42.9	13.1	475.0	59.9	NO	Yes	No
	NO. 9 SULFURIC ACID PLANT	6	MFR9SAP	362900	3082500	150	45.7	9.0	2.74	155	341	44.8	13.7	475.0	59.9	NO	Yes	No
			MFRSAP	362900	3082500	150	45.7	7.5	2.29	152	340	41.5	12.6	1,417.0	178.5	NO	Yes	No
	DAP Manufacturing Plant	7	MFRDAP	362900	3082500	126	38.4	8.0	2.44	104	313	34.5	10.5	30.40	3.8	CON	Yes	Yes
	No. 5 DAP Plant	55	MFR5DAP	362900	3082500	133	40.5	7.0	2.13	110	316	67.6	20.6	12.7	1.6	CON	Yes	Yes
			MFRDAP	362900	3082500	126	38.4	8	2.44	104	313	34.5	10.5	43.1	5.4	CON	Yes	Yes
	TANK Nos. 1, 2, and 3 for molten sulfur storage w/scrubber	63	MFRT123	362900	3082500	33	10.1	0.8	0.25	110	316	20.5	6.24	0.40	0.1	CON	Yes	Yes
	AFI PLANT NO. 1	78	MFR1AFI	362900	3082500	136	41.5	6.0	1.83	150	339	64.5	19.7	23.51	3.0	CON	Yes	Yes
	AFI PLANT NO. 2	103	MFR2AFI	362900	3082500	155	47.2	6.0	1.83	150	339	64.5	19.7	23.51	3.0	CON	Yes	Yes
			MFRAFI	362900	3082500	136	41.5	6.0	1.83	150	339	64.5	19.7	47.0	5.9	CON	Yes	Yes
	Ammonia Plant (Expanding Source)		AMMPLTB	362900	3082500	60	18.3	8.3	2.53	600	589	22.7	6.93	-32.80	-4.13	EXP	No	Yes
	Sodium Silicofluoride/Sodium Fluoride Plant (Expanding Source)		SSFSFPB	362900	3082500	28	8.5	2.5	0.76	95	308	11.6	3.55	-0.20	-0.0252	EXP	No	Yes
	No. 10 KVS Mill (Expanding Source)		10KVSMB	362900	3082500	87	26.5	1.7	0.52	118	321	59.8	18.24	-0.020	-0.0025	EXP	No	Yes
	No. 12 KVS Mill (Expanding Source)		12KVSMB	362900	3082500	71	21.6	1.6	0.49	135	330	68.5	20.87	-0.040	-0.0050	EXP	No	Yes
	No. 7 Oil-Fired Concentrator (Expanding Source)		7OFCONB	362900	3082500	78	23.8	6.0	1.83	165	347	17.2	5.24	-41.40	-5.22	EXP	No	Yes
	No. 8 Oil-Fired Concentrator (Expanding Source)		8OFCONB	362900	3082500	78	23.8	6.0	1.83	159	344	16.7	5.10	-39.70	-5.00	EXP	No	Yes
			MFRSS80	362900	3082500	78	23.8	6.0	1.83	165	347	17.2	5.2	-81.36	-10.25	EXP	No	Yes
	GTSP Plant (Expanding Source)		GTSPAPB	362900	3082500	126	38.4	8.0	2.44	129	327	34.9	10.65	-71.40	-9.00	EXP	No	Yes
	No. 5 and No. 9 Mills Bag Filter (Expanding Source)		RKML59B	362900	3082500	66	20.1	2.0	0.61	115	319	58.3	17.75	-0.010	-0.0013	EXP	No	Yes
	No. 3 Continuous Triple Dryer (Expanding Source)		3CONTDB	362900	3082500	68	20.7	3.5	1.07	115	319	45.8	13.96	-22.80	-2.87	EXP	No	Yes
	No. 4 Continuous Triple Dryer (Expanding Source)		4CONTDB	362900	3082500	68	20.7	3.5	1.07	134	330	61.8	18.85	-23.20	-2.92	EXP	No	Yes
			MFRCONT	362900	3082500	68	20.7	3.5	1.07	115	319	45.8	14.0	-46.01	-5.80	EXP	No	Yes
	Molten Sulfur Handling- Pits 7 & 8 (Expanding Source)		MSPTSB	362900	3082500	8	2.4	3.3	1.00	0	0	0.3	0.10	-0.080	-0.0101	EXP	No	Yes
	Molten Sulfur Handling- Pits 4,5, & 6 (Expanding Source)		PTS456B	362900	3082500	8	2.4	3.3	1.00	0	0	0.3	0.10	-0.13	-0.0166	EXP	No	Yes
			MFRMSH	362900	3082500	8	2.4	3.3	1.00	0	0	0.3	0.1	-0.21	-0.03	EXP	No	Yes
	Molten Sulfur Handling- Tanks (Expanding Source)		MSTKTLB	362900	3082500	36	11.0	3.3	1.00		0	0.3	0.10	-2.12	-0.27	EXP	No	Yes
	No. 4 Sulfuric Acid Plant (Expanding Source)		NO4SAPB	362900	3082500	80	24.4	4.7	1.43	194	363	20.4	6.23	-282.00	-35.53	EXP	No	Yes
	No. 5 Sulfuric Acid Plant (Expanding Source)		NO5SAPB	362900	3082500	74	22.6	5.3	1.62	189	360	25.3	7.72	-480.00	-60.48	EXP	No	Yes
	No. 6 Sulfuric Acid Plant (Expanding Source)		NO6SAPB	362900	3082500	72	21.9	5.9	1.80	189	360	31.3	9.53	-688.00	-86.69	EXP	No	Yes
	No. 7 Sulfuric Acid Plant (Expanding Source)		NO7SAPB	362900	3082500	92	28.0	9.4	2.87	183	357	22.3	6.80	-1,503.00	-189.38	EXP	No	Yes
	No. 8 Sulfuric Acid Plant (Expanding Source)		NO8SAPB	362900	3082500	96	29.3	10.7	3.26	174	352	24.2	7.37	-1,679.00	-211.55	EXP	No	Yes
	No. 4-8 Sulfuric Acid Plant (Expanding Source)		MFRSAPB	362900	3082500	92	28.0	9.4	2.87	183	357	22.3	6.8	-4,632.00	-583.63	EXP	No	Yes

TABLE A-2
DETAILED STACK, OPERATING, AND SO_2 EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters Height (ft)	Height (m)	Diameter (ft)	Diameter (m)	Temperature (°F)	Temperature (K)	Velocity (ft/s)	Velocity (m/s)	SO_2 Emission Rate (lb/hr)	SO_2 Emission Rate (g/s)	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
0570039	TECO - Big Bend Station																	
	Unit #1 Coal Fired Boiler w/ ESP	1	TECOBB1	361,900	3,075,000	490	149.35	24.0	7.3	294	419	115.9	35.3	26240.5	3306.30	NO	Yes	No
	Unit #2 Riley-Stoker Coal Boiler w/ Esp	2	TECOBB2	361,900	3,075,000	490	149.35	24.0	7.3	125	325	87.6	26.7	25974.0	3272.72	NO	Yes	No
	Unit #3 Riley-Stoker Coal Boiler w/ ESP	3	TECOBB3	361,900	3,075,000	499	152.10	24.0	7.3	279	410	47.0	14.3	26747.5	3370.19	CON	Yes	Yes
	Unit #4 Coal Boiler W/ Belco ESP Psd-Fl-040	4	TECOBB4	361,900	3,075,000	499	152.10	24.0	7.3	156	342	59.0	18.0	3551.0	447.43	CON	Yes	Yes
	Combustion Turbine #2 - No. 2 Fuel Oil	5	TECOBB5	361,900	3,075,000	75	22.86	14.0	4.3	928	771	61.0	18.6	277.0	34.90	NO	Yes	No
	Combustion Turbine #3 - No. 2 Fuel Oil	6	TECOBB6	361,900	3,075,000	75	22.86	14.0	4.3	928	771	61.0	18.6	277.0	34.90	NO	Yes	No
	Combustion Turbine #2 & 3 - No. 2 Fuel Oil	5 - 6	TECOBB56	361,900	3,075,000	75	22.9	14.0	4.27	928	771	61.0	18.6	554.0	69.8	NO	Yes	No
	Combustion Turbine #1 - No. 2 Fuel Oil	7	TECOBB7	361,900	3,075,000	35	10.67	11.0	3.4	1010	816	91.9	28.0	79.0	9.95	NO	Yes	No
	Steam Generators 1 & 2 Baseline	16	TCBB12B	361,900	3,075,000	490	149.35	24.0	7.3	300	422	94.0	28.7	-19333.3	-2436.0	EXP	No	Yes
	Steam Generator 3 Baseline	17	TCBB3B	361,900	3,075,000	490	149.35	24.0	7.3	293	418	47.0	14.3	-9666.7	-1218.0	EXP	No	Yes
	Eus 16 & 17 are modeled using TCBB3B		TCBB3B	361900	3075000	490	149.35	24.0	7.3	293	418	47.0	14.3	-29000.0	-3654.0	EXP	No	Yes
0570057	Enviro Focus Technologies, LLC																	
	Blast Furnace	1	EFT001	364,000	3,093,500	150	45.72	3.0	0.9	160	344	54.8	16.7	76.6	9.65	CON	Yes	Yes
0570261	Hillsborough Co. R.R.F.																	
	Municipal Waste Combustor & Auxiliary burners-Unit #1	1	HCRRF1	368,200	3,092,690	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #2	2	HCRRF2	368,200	3,092,690	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary burners-Unit #3	3	HCRRF3	368,200	3,092,690	220	67.1	5.1	1.55	290	416	72.5	22.1	32.86	4.140	CON	Yes	Yes
	Eus 1, 2,& 3 are modeled using HCRRF1		HCRRF13	368200	3092690	220	67.1	5.1	1.55	290	416	72.5	22.1	98.58	12.421	CON	Yes	Yes
0810010	Florida Power & Light - Manatee																	
	Generator Unit 1	1	FPLMAN1	367,250	3,054,150	499	152.1	26.2	8.0	325	436	68.7	20.9	9515	1198.9	CON	Yes	Yes
	Generator Unit 2	2	FPLMAN2	367,250	3,054,150	499	152.1	26.2	8.0	325	436	68.7	20.9	9515	1198.9	CON	Yes	Yes
	Eus 1 & 2 are modeled using FPLMAN1		FPLMAN12	367250	3054150	499	152.1	26.2	8.0	325	436	68.7	20.9	19030	2397.8	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3A	5	FPLMAN5	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	13.3	1.68	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3B	6	FPLMAN6	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	13.3	1.68	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3C	7	FPLMAN7	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	13.3	1.68	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3D	8	FPLMAN8	367,250	3,054,150	120	36.6	19.0	5.8	202	368	59.0	18.0	13.3	1.68	CON	Yes	Yes
	Eus 5,6,7,& 8 are modeled using FPLMAN5		FPLMAN58	367250	3054150	120	36.6	19.0	5.8	202	368	59.0	18.0	53.2	6.70	CON	Yes	Yes
1010017	Progress Energy Florida, Inc. - Anclote Power Plant																	
	Steam Turbine Gen. Anclote Unit No.1	1	PEFANC1	327,410	3,120,680	499	152.10	24	7.3	320	433	62.0	18.9	13950.8	1757.8	NO	Yes	No
	Steam Turbine Gen. Anclote Unit No.2	2	PEFANC2	327,410	3,120,680	499	152.10	24	7.3	320	433	62.0	18.9	13631.8	1717.6	NO	Yes	No
	Steam Turbine Gen. Anclote Unit Nos. 1 & 2	1 - 2	FPCANC12	327,410	3,120,680	499	152.1	24.0	7.32	320	433	62.0	18.9	27,582.5	3,475.4	NO	Yes	No

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Baseline Source, does not affect PSD increment.
ND = No data available.

TABLE A-3
DETAILED STACK, OPERATING, AND NO_x EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	NOx Emission Rate TPY	NOx Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
0570028	*National Gypsum Co.*																	
	#1 Calcidyne Unit	21	NGC21	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	3.1	0.09	NO	Yes	No
	#2 Calcidyne Unit	22	NGC22	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	3.1	0.09	NO	Yes	No
	#3 Calcidyne Unit	23	NGC23	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	3.1	0.09	NO	Yes	No
	#4 Calcidyne Unit	24	NGC24	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	3.1	0.09	NO	Yes	No
	#1 - #4 Calcidyne Units	21 - 24	NGC2124	348,830	3,082,690	42	12.8	1.1	0.34	350	450	62.0	18.9	12.3	0.35	NO	Yes	No
	No. 5 Calcidyne Unit	28	NGC28	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	NO	Yes	No
	No. 6 Calcidyne Unit	29	NGC29	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	NO	Yes	No
	No. 7 Calcidyne Unit	30	NGC30	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	NO	Yes	No
	No. 8 Calcidyne Unit	31	NGC31	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	NO	Yes	No
	Nos. 5 - 8 Calcidyne Units	28 - 31	NGC2831	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	12.3	0.35	NO	Yes	No
	Wallboard Kiln No. 2	34	NGC34	348,830	3,082,690	47	14.3	2.5	0.76	309	427	67.0	20.4	46.0	1.32	NO	Yes	No
	Ten Deck Kiln Dryer In Board Plant No. 1	47	NGC47	348,830	3,082,690	35	10.7	2.8	0.85	300	422	64.0	19.5	46.4	1.34	CON	Yes	Yes
	No. 9 Calcidyne Unit	100	NGC100	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	CON	Yes	Yes
	No. 10 Calcidyne	101	NGC101	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	3.1	0.09	CON	Yes	Yes
	No. 9 & 10 Calcidyne Units	100 - 101	NGC10X	348,830	3,082,690	42	12.8	1.1	0.34	350	450	71.9	21.9	6.1	0.2	CON	Yes	Yes
	Rock Dryer & Crusher	36	NGC36	348,830	3,082,690	64	19.5	3.5	1.07	185	358	38.7	11.8	18.4	0.53	NO	Yes	No
	Impact Mill #1	102	NGC102	348,830	3,082,690	90	27.4	3.9	1.19	200	366	44.6	13.6	9.1	0.26	CON	Yes	Yes
	Impact Mill #2	103	NGC103	348,830	3,082,690	90	27.4	3.0	0.91	200	366	75.5	23.0	9.1	0.26	CON	Yes	Yes
1030117	PINELLAS CO. RESOURCE RECOVERY FACILITY																	
	Municipal Ewaste Combustor Unit 1	1	PNRRF1	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	899.0	25.86	NO	Yes	No
	Municipal Ewaste Combustor Unit 2	2	PNRRF2	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	899.0	25.86	NO	Yes	No
	Municipal Ewaste Combustor Unit 3	3	PNRRF3	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	899.0	25.86	NO	Yes	No
	Municipal Ewaste Combustor Units 1 - 3	1 - 3	PNRRF13	335,200	3,084,100	165	50.3	8.5	2.59	270	405	71.4	21.8	2,697.0	77.6	NO	Yes	No
1030013	FPC -Bayboro Plant																	
	Combustion Turbine Peaking Unit # 1	1	FPCBAY1	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	985.9	28.36	NO	Yes	No
	Combustion Turbine Peaking Unit # 2	2	FPCBAY2	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	1,013.8	29.16	NO	Yes	No
	Combustion Turbine Peaking Unit # 3	3	FPCBAY3	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	935.4	26.91	NO	Yes	No
	Combustion Turbine Peaking Unit # 4	3	FPCBAY4	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	902.8	25.97	NO	Yes	No
	Combustion Turbine Peaking Units # 1 - 4	1 - 4	FBCBAY14	338,800	3,071,300	40	12.2	22.9	6.98	900	755	21.0	6.4	3,837.8	110.4	NO	Yes	No
1030012	Progress Energy Florida - Higgins																	
	FFFSG-SG 1 (Phase II, Acid Rain Unit)	1	FPCHIG1	336,500	3,098,400	174	53.0	12.5	3.81	310	428	27.0	8.2	752.1	21.64	NO	Yes	No
	FFFSG-SG 2 (Phase II, Acid Rain Unit)	2	FPCHIG2	336,500	3,098,400	174	53.0	12.5	3.81	310	428	27.0	8.2	752.1	21.64	NO	Yes	No
	FFFSG-SG 3 (Phase II, Acid Rain Unit)	3	FPCHIG3	336,500	3,098,400	174	53.0	12.5	3.81	310	428	27.0	8.2	752.1	21.64	NO	Yes	No
	FFFSG-SG 1 - 3 (Phase II, Acid Rain Units)	1 - 3	FPCHIG13	336,500	3,098,400	174	53.0	12.5	3.81	310	428	27.0	8.2	2,256.3	64.9	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 1	4	FPCHIG4	336,500	3,098,400	55	16.8	15.1	4.60	850	728	93.1	28.4	423.8	12.19	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 2	5	FPCHIG5	336,500	3,098,400	55	16.8	15.1	4.60	850	728	93.1	28.4	423.8	12.19	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 3	6	FPCHIG6	336,500	3,098,400	55	16.8	15.1	4.60	850	728	93.1	28.4	472.4	13.59	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 4	7	FPCHIG7	336,500	3,098,400	55	16.8	15.1	4.60	850	728	93.1	28.4	472.4	13.59	NO	Yes	No
	Combustion Turbine Peaking Unit-CTP 1 - 4	4 - 7	FPCHIG47	336,500	3,098,400	55	16.8	15.1	4.60	850	728	93.1	28.4	1,792.4	51.6	NO	Yes	No
0570038	TECO, Hookers Point																	
	Boiler #1	1	TECOHK1	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-530.0	-15.25	EXP	No	Yes
	Boiler #2	2	TECOHK2	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-530.0	-15.25	EXP	No	Yes
	Boiler #5	5	TECOHK5	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-1,064.0	-30.61	EXP	No	Yes
	Boilers #1, #2, & #5	1, 2, 5	TECOHK15	358,000	3,091,000	280	85.3	11.3	3.44	356	453	82.0	25.0	-2,124.0	-61.1	EXP	No	Yes
	Boiler #3	3	TECOHK3	358,000	3,091,000	280	85.3	12.0	3.66	341	445	62.7	19.1	-731.0	-21.03	EXP	No	Yes
	Boiler #4	4	TECOHK4	358,000	3,091,000	280	85.3	12.0	3.66	341	445	62.7	19.1	-731.0	-21.03	EXP	No	Yes
	Bolers #3 & #4	3 - 4	TECOHK34	358,000	3,091,000	280	85.3	12.0	3.66	341	445	62.7	19.1	-1,462.0	-42.1	EXP	No	Yes
	Boiler #6	6	TECOHK6	358,000	3,091,000	280	85.3	9.4	2.87	329	438	75.2	22.9	-972.0	-27.96	EXP	No	Yes
	30 Caterpillar XQ2000 Power Modules	8 - 37	TECOHKPM	358,000	3,091,000	10	3.0	0.7	0.20	808	704	681.0	207.6	582.0	16.74	CON	Yes	Yes
0570040	TECO, Bayside Power Station																	

TABLE A-3

DETAILED STACK, OPERATING, AND NO_x EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	NOx Emission Rate TPY	NOx Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
	Unit #1 125 MW Coal Fired Boiler with Steam Generator	1	TECOBA1	360,100	3,087,500	315	96.0	10.0	3.05	300	422	100.0	30.5	-8,055.0	-231.7	EXP	No	Yes
	Unit #2 125 MW Coal Fired Boiler with Steam Generator	2	TECOBA2	360,100	3,087,500	315	96.0	10.0	3.05	300	422	100.0	30.5	-8,314.0	-239.2	EXP	No	Yes
	Unit #3 180 MW Coal Fired Boiler with Steam Generator	3	TECOBA3	360,100	3,087,500	315	96.0	10.0	3.05	300	422	100.0	30.5	-10,518.0	-302.6	EXP	No	Yes
	Unit #4 188 MW Coal Fired Boiler with Steam Generator	4	TECOBA4	360,100	3,087,500	315	96.0	10.0	3.05	300	422	100.0	30.5	-11,555.0	-332.4	EXP	No	Yes
	Units #1 - #4 Coal Fired Boilers with Steam Generators	1 - 4	TECOBA14	360,100	3,087,500	315	96.0	10.0	3.05	300	422	100.0	30.5	-38,442.0	-1,105.9	EXP	No	Yes
	Unit #5 239 MW Coal Fired Boiler with Steam Generator	5	TECOBA5	360,100	3,087,500	315	96.0	14.6	4.45	303	424	76.0	23.2	-15,128.0	-435.2	EXP	No	Yes
	Unit #6 414 MW Coal Fired Boiler with Steam Generator	6	TECOBA6	360,100	3,087,500	315	96.0	17.6	5.36	320	433	81.0	24.7	-24,957.0	-717.9	EXP	No	Yes
	14 MW Gas-Fired Turbine	7	TECOBA7	360,100	3,087,500	35	10.7	11.0	3.35	1,010	816	92.6	28.2	-561.0	-16.1	EXP	No	Yes
	Bayside Unit 1A – 170 MW combined cycle gas turbine	20	TECOBA20	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 1B – 170 MW combined cycle gas turbine	21	TECOBA21	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 1C – 170 MW combined cycle gas turbine	22	TECOBA22	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 2A – 170 MW combined cycle gas turbine	23	TECOBA23	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 2B – 170 MW combined cycle gas turbine	24	TECOBA24	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 2C – 170 MW combined cycle gas turbine	25	TECOBA25	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Unit 2D – 170 MW combined cycle gas turbine	26	TECOBA26	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	101.2	2.9	CON	Yes	Yes
	Bayside Units 1A,B,C & 2A,B,C,D – 170 MW combined cycle gas turbines	20 - 26	TECOBA2X	360,100	3,087,500	150	45.7	19.0	5.79	220	378	60.5	18.4	708.4	20.4	CON	Yes	Yes
0570127	Mckay Bay Refuse-To-Energy Facility																	
	Unit #1 - The West Most Unit.	1	MBREF1	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	-329.0	-9.5	EXP	No	Yes
	Unit#2 - Second West Most Unit. Burns Municipal Waste Only.	2	MBREF2	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	-329.0	-9.5	EXP	No	Yes
	Unit #3 - 3rd Westmost Unit - Burns Municipal Waste.	3	MBREF3	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	-329.0	-9.5	EXP	No	Yes
	Unit #4 - East Most Unit. Burns Municipal Waste.	4	MBREF4	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	-329.0	-9.5	EXP	No	Yes
	Units #1 - #4	1 - 4	MBREF14	360,200	3,092,210	160	48.8	5.7	1.74	450	505	41.0	12.5	-1,316.0	-37.9	EXP	No	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 1	103	MBREF103	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	169.8	4.9	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 2	104	MBREF104	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	169.8	4.9	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 3	105	MBREF105	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	169.8	4.9	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Unit No. 4	106	MBREF106	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	169.8	4.9	CON	Yes	Yes
	Municipal Waste Combustor & Auxiliary Burners - Units No. 1 - 4	103 - 106	MBREF10X	360,200	3,092,210	201	61.3	4.2	1.28	289	416	73.3	22.3	679.0	19.5	CON	Yes	Yes
0570008	Mosaic Riverview Facility																	
	DAP Manufacturing Plant	7	MOSRIV7	362,900	3,082,500	126	38.4	8.0	2.44	104	313	34.5	10.5	35.0	1.0	NO	Yes	No
	No. 3 MAP Plant	22	MOSRIV22	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	0.7	0.02	NO	Yes	No
	No. 4 MAP Plant	23	MOSRIV23	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	0.7	0.02	NO	Yes	No
	South Cooler	24	MOSRIV24	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	0.7	0.02	NO	Yes	No
	Nox. 3 & 4 MAP Plants and South Cooler	22 - 24	MOSRIV2X	362,900	3,082,500	133	40.5	7.0	2.13	142	334	71.5	21.8	2.1	0.06	NO	Yes	No
	No. 5 DAP Plant	55	MOSRIV55	362,900	3,082,500	133	40.5	7.0	2.13	110	316	67.6	20.6	17.5	0.50	NO	Yes	No
	No. 7 SAP	4	MOSRIV4	362,900	3,082,500	150	45.7	7.5	2.29	152	340	41.5	12.6	70.1	2.02	NO	Yes	No
	No. 8 SAP	5	MOSRIV5	362,900	3,082,500	150	45.7	8.0	2.44	165	347	42.9	13.1	59.1	1.70	NO	Yes	No
	No. 9 SAP	6	MOSRIV6	362,900	3,082,500	150	45.7	9.0	2.74	155	341	44.8	13.7	74.5	2.14	NO	Yes	No
	Animal Feed Ingredient Plant No. 1	78	MOSRIV78	362,900	3,082,500	136	41.5	6.0	1.83	150	339	64.5	19.7	21.9	0.63	CON	Yes	Yes
	Animal Feed Ingredient Plant No. 2	103	MOSRI103	362,900	3,082,500	155	47.2	6.0	1.83	150	339	64.5	19.7	32.9	0.95	CON	Yes	Yes
	Baseline - No. 3 and No. 4 MAP Plants and South Cooler		MAP34CB	362,900	3,082,500	90	27.4	3.3	1.01	140	333	67.0	20.4	-0.4	-0.01	EXP	No	Yes
	Baseline - No. 5 DAP Plant		NO5DAPB	362,900	3,082,500	133	40.5	7.0	2.13	108	315	50.5	15.4	-2.4	-0.07	EXP	No	Yes
	Baseline - Auxiliary Steam Boiler		AUXSTB	362,900	3,082,500	20	6.1	4.5	1.37	420	489	41.2	12.6	-0.8	-0.02	EXP	No	Yes
	Baseline - Sodium Silicofluoride/Sodium Fluoride Plant		SSFSFPB	362,900	3,082,500	40	12.2	1.7	0.51	120	322	41.1	12.5	-0.7	-0.02	EXP	No	Yes
	Baseline - Phosphate Rock Grinding/Drying System		RKGRNDB	362,900	3,082,500	60	18.3	1.9	0.59	140	333	57.6	17.5	-0.1	-0.0014	EXP	No	Yes
	Baseline - GTSP/DAP Manufacturing Plant		GTSPAPB	362,900	3,082,500	126	38.4	8.0	2.44	125	325	46.4	14.1	-6.1	-0.18	EXP	No	Yes
	Baseline - No. 9 Sulfuric Acid Plantb		NO9SAPB	362,900	3,082,500	150	45.7	9.0	2.74	152	340	39.0	11.9	-41.4	-1.19	EXP	No	Yes
	Baseline - No. 8 Sulfuric Acid Plantb		NO8SAPB	362,900	3,082,500	150	45.7	8.0	2.44	150	339	34.8	10.6	-28.1	-0.81	EXP	No	Yes
	Baseline - No. 7 Sulfuric Acid Plantb		NO7SAPB	362,900	3,082,500	150	45.7	7.5	2.29	170	350	46.0	14.0	-30.9	-0.89	EXP	No	Yes
0570039	TECO - Big Bend Station																	
	Unit #1 Coal Fired Boiler w/ ESP	1	TECOBB1	361,900	3,075,000	490	149.4	24.0	7.32	294	419	115.9	35.3	27,029.0	777.5	NO	Yes	No
	Unit #2 Riley-Stoker Coal Boiler w/ Esp	2	TECOBB2	361,900	3,075,000	490	149.4	24.0	7.32	125	325	87.6	26.7	27,118.0	780.1	NO	Yes	No
	Unit #3 Riley-Stoker Coal Boiler w/ ESP	3	TECOBB3	361,900	3,075,000	499	152.1	24.0	7.32	279	410	47.0	14.3	12,619.0	363.0	NO	Yes	No
	Unit #4 Coal Boiler W/ Belco ESP	4	TECOBB4	361,900	3,075,000	499	152.1	24.0	7.32	156	342	59.0	18.0	11,379.0	327.3	NO	Yes	No
	Combustion Turbine #2 - No. 2 Fuel Oil	5	TECOBB5	361,900	3,075,000	75	22.9	14.0	4.27	928	771	61.0	18.6	1,958.0	56.3	NO	Yes	No
	Combustion Turbine #3 - No. 2 Fuel Oil	6	TECOBB6	361,900	3,075,000	75	22.9	14.0	4.27	928	771	61.0	18.6	1,958.0	56.3	NO	Yes	No
	Combustion Turbine #2 & 3 - No. 2 Fuel Oil	5 - 6	TECOBB56	361,900	3,075,000	75	22.9	14.0	4.27	928	771	61.0	18.6	3,916.0	112.7	NO	Yes	No

TABLE A-3

DETAILED STACK, OPERATING, AND NO_x EMISSIONS FOR SOURCES INCLUDED IN THE AIR MODELING ANALYSES FOR THE BARTOW POWER PLANT

Facility ID	Facility Name / Emission Unit Description	EU ID	AERMOD ID Name	UTM Location X (m)	UTM Location Y (m)	Stack Parameters: Height ft	Height m	Diameter ft	Diameter m	Temperature °F	Temperature K	Velocity ft/s	Velocity m/s	NOx Emission Rate TPY	NOx Emission Rate g/s	PSD Source? (EXP/CON)	Modeled in AAQS	Modeled in PSD Class II
	Combustion Turbine #1 - No. 2 Fuel Oil	7	TECOBB7	361,900	3,075,000	35	10.7	11.0	3.36	1,010	816	91.9	28.0	561.0	16.1	NO	Yes	No
0570029	Kinder Morgan Port Sutton Terminal																	
	Package Boiler Units 3 & 4	3,4	KMPST3&4	362,500	3,089,000	30	9.1	4.5	1.37	450	505	35.3	10.8	54.8	1.58	CON	Yes	Yes
	Nitric Acid Plant with 2 Stacks	7	KMPST7	362,500	3,089,000	55	16.8	2.5	0.76	250	394	121.0	36.9	287.2	8.26	NO	Yes	No
	Gas Fired Hurst Package Boiler	13	KMPST13	362,500	3,089,000	9	2.7	1.7	0.52	260	400	24.0	7.3	7.6	0.22	CON	Yes	Yes
0570261	Hillsborough Cty. RRF																	
	Unit #1 - The West Most Unit.	1	HCRRF1	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	256.0	7.36	CON	Yes	Yes
	Unit #2 - Second West Most Unit. Burns Municipal Waste Only.	2	HCRRF2	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	256.0	7.36	CON	Yes	Yes
	Unit #3 - 3rd Westmost Unit - Burns Municipal Waste.	3	HCRRF3	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	256.0	7.36	CON	Yes	Yes
	Units #1 - #3	1 - 3	HCRRF13	368,200	3,092,700	220	67.1	5.1	1.55	290	416	72.5	22.1	768.0	22.1	CON	Yes	Yes
0810010	Florida Power & Light - Manatee																	
	Generator Unit 1	1	FPLMAN1	367,250	3,054,150	499	152.1	26.2	7.99	325	436	68.7	20.9	11,366.0	326.97	NO	Yes	No
	Generator Unit 2	2	FPLMAN2	367,250	3,054,150	499	152.1	26.2	7.99	325	436	68.7	20.9	11,366.0	326.97	NO	Yes	No
	Generator Units 1 & 2	1 - 2	FPLMAN12	367,250	3,054,150	499	152.1	26.2	7.99	325	436	68.7	20.9	22,732.0	653.9	NO	Yes	No
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3A	5	FPLMAN5	367,250	3,054,150	120	36.6	19.0	5.79	202	368	59.0	18.0	103.4	2.97	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3B	6	FPLMAN6	367,250	3,054,150	120	36.6	19.0	5.79	202	368	59.0	18.0	103.4	2.97	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3C	7	FPLMAN7	367,250	3,054,150	120	36.6	19.0	5.79	202	368	59.0	18.0	103.4	2.97	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit No.3D	8	FPLMAN8	367,250	3,054,150	120	36.6	19.0	5.79	202	368	59.0	18.0	103.4	2.97	CON	Yes	Yes
	Gas Turbine (nominal 170 MW) with HRSG- Unit Nos. 3A,B,C,D	5 - 8	FPLMAN58	367,250	3,054,150	120	36.6	19.0	5.79	202	368	59.0	18.0	413.6	11.9	CON	Yes	Yes
1010017	Progress Energy-Anclote Power Plant																	
	Steam Turbine Gen. Anclote Unit No.1	1	FPCANC1	327,410	3,120,680	499	152.1	24.0	7.32	320	433	62.0	18.9	6,812.6	195.98	NO	Yes	No
	Steam Turbine Gen. Anclote Unit No.2	2	FPCANC2	327,410	3,120,680	499	152.1	24.0	7.32	320	433	62.0	18.9	6,656.1	191.48	NO	Yes	No
	Steam Turbine Gen. Anclote Unit Nos. 1 & 2	1 - 2	FPCANC12	327,410	3,120,680	499	152.1	24.0	7.32	320	433	62.0	18.9	13,468.7	387.5	NO	Yes	No

Note: EXP = PSD expanding source.
CON = PSD consuming source.
NO = Baseline Source, does not affect PSD increment.

BEST AVAILABLE COPY

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

August 30, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Rufus Jackson
Authorized Representative
Florida Power Corporation dba
Progress Energy Florida
1601 Weedon Island Drive
St. Petersburg, Florida 33711

Re: DEP File Nos. PSD-FL-381 and 1030011-010-AC
P.L. Bartow Power Plant Repowering Project
Request for Additional Information

Dear Mr. Jackson:

On July 31, 2006 the Department received your application for an air construction permit for the natural gas combined cycle repowering of the steam turbine-electrical generators (STGs) associated with existing fossil-fuel fired Units 1, 2, and 3 at the Progress Energy P.L. Bartow Power Plant in Pinellas County.

The three furnaces/boilers presently firing residual fuel oil and providing steam to the three STGs will be replaced by four natural gas and distillate fuel oil-fired Siemens STG6-PAC-5000F combustion turbine-electrical generators (CTs) and four duct-fired heat recovery steam generators (HRSGs). The project also included a separate CT for use in simple cycle mode.

According to the application, there will be emission reductions of certain pollutants such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), sulfuric acid mist and nitrogen oxides (NO_X). An Air Construction Permit pursuant to the Rules for the Prevention of Significant Air Quality (AC/PSD Permit) is required for increased emissions of carbon monoxide (CO) and volatile organic compounds (VOC).

The application is incomplete. In order to continue processing your application, the Department will need the additional information below. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

SENDER: COMPLETE THIS SECTION

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

1. Article Addressed to:

Mr. Rufus Jackson
Authorized Representative
Florida Power Corporation dba
Progress Energy Florida
1601 Weedon Island Drive
St. Petersburg, Florida 33711

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X ☐ Agent ☐ Addressee

B. Received by (Printed Name) C. Date of Delivery

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

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

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7000 1670 0013 3110 1182

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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

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Mr. Rufus Jackson
Authorized Representative
Florida Power Corporation dba
Progress Energy Florida
1601 Weedon Island Drive
St. Petersburg, Florida 33711

PS Form 3800, May 2000 See Reverse for Instructions

1. Please provide Siemens brochures and information for the CTs. Include heat rate, heat input curves, etc.
2. Please provide the manufacturer's curves showing expected NO_X, CO, VOC and formaldehyde concentrations with respect to CT load as percent of full load.
3. Earlier versions of the Siemens CTs that will be installed at the Bartow Plant have been operating for several years at the Hines Energy Complex in Polk County. The Hines CTs are the previously designated Westinghouse or Siemens-Westinghouse 501F Series. Provide the results of CO and VOC acceptance and compliance tests and any tests conducted at partial loads. Include as well any tests conducted while firing fuel oil.
4. Provide the project estimates for 24-hour CO emission values when operating in: normal gas-fired mode; using the duct burners; power augmentation or peaking if practiced; and fuel oil firing. What kind of 12-month rolling average can be achieved considering all the modes of operation combined? Any CEMS CO information from units at Hines would be useful in this regard although the Siemens CT's might have been improved since construction of the previous versions.
5. Please update the costs of oxidation catalyst. The Department obtained lower capital cost estimates from suppliers than submitted by applicants during permitting of several recent projects. We can discuss the details to properly frame the assumptions for potential suppliers. Following are some points to consider in the update:
   - Typically costs are acknowledged for additional fuel use to account loss of any capacity when using catalyst but not the value of lost electric sales. These aspects of the oxidation catalyst cost-effectiveness estimate should be updated.
   - Check to make sure that credit is taken for returning spent catalyst to the supplier.
   - Oxidation catalyst typically lasts much longer than three years. A more realistic lifetime should be assumed rather than just assuming that the catalyst requires replacement after three years.
   - It would be easy enough to inquire from Seminole Electric how often they have added or changed catalyst on their Siemens-Westinghouse 501F combined cycle units at their Payne Creek Plant.
6. Some recognition needs to be given in the oxidation catalyst evaluation for the benefits of VOC and formaldehyde reduction potential.
7. Refer to the Interim Project Configuration (Section 2.3, Page 8 of the Application PSD report). Up to two simple cycle CTs will start up prior to the shut down of the three furnaces/boilers. To avoid PSD applicability during the simple cycle phase, creditable emission reductions must be federally enforceable as a practical matter at and after the time that actual construction on the project(s) begins. Also the actual reductions must take place before the date that the emissions increase from any of the new units occurs.

8. The scenario presented in Table 2-2 includes separate 6-month periods. The first 6 months represents operation of the existing boilers. The second 6-months represent combined cycle operation only. However, no emissions scenario is presented when the existing units will be operating concurrently with the one or two simple cycle turbines as described elsewhere in the application. If existing units are operating at the same time with new units, please submit proposed operating emissions scenarios and calculations. Refer to Rule 62-210.200(179)(f) "Net Emissions Increase".

9. The project addresses contemporaneous emission increases/decreases related to the three fossil fuel fired steam generators. Pursuant to Rule 62-210.400(2) F.A.C, please assess and if necessary resubmit the emissions netting calculation considering the five year contemporaneous period for this modification and include any other increases or decreases from any other emission unit or project at the facility.

10. If any of the pollutants exceed the PSD significant threshold level due to the new calculations, please submit the appropriate BACT analysis for that pollutant. Please refer to Rule 62-212.400 (2)3. Hybrid Test for Multiple Types of Emissions Units and to the Rule 62-210.200 (34) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL"; Rule 62-210.200 (179) "Net Emissions Increase".

11. Submit a milestone chart showing: when each existing boiler is destined to be shut down in 2009; when any CTs will commence operation in simple cycle mode; and when each CT will commence operation in combined cycle mode.

12. Will the hourly potential emissions increase beyond their present potential during any time in 2006? For how long and for which pollutants?

13. Submit tables, timelines or charts showing how each of the requirements of the definition of "Net Emissions Increase" at Section 62-210.200(179) will be met.

14. What is the ammonia slip proposed for this project (ppm)?

15. The application only lists the 5CTs, 4HRSGs, one auxiliary boiler and 5 heaters. Would this plant include Cooling Tower, an Emergency Generator and Diesel Fired Pump, or any other ancillary equipment? If so, please provide information about these units.

16. Is there another future phase for this facility's repowering project?

17. Section 6-5 of the application states that the "FDEP considers this station (Tampa) to have surface meteorological data representative of the project site." The FDEP can not determine if the Tampa International Airport surface data is representative without further information regarding the surface land use data at the facility. Please provide information to support the conclusion that the Tampa International surface data is most representative for this project.

18. Although PM, NOx and SO2 are not subject to PSD, the applicant provided a Significant Impact Analysis for these pollutants to conclude compliance with the respective Class II Increment. The results of the modeling concluded that the impacts were above the Class II Significant Impact Levels. Therefore, since the impacts are "Significant" and the future stacks will be much lower, the Department requests more detailed modeling to ensure that the increment and the Ambient Air Quality Standards are not exceeded due to this modification. Please provide a full Increment and AAQS analysis.

19. Please provide further information regarding the short term emission rates used in the modeling analysis. For CO, Table 2-1, states that simple cycle operation will emit 154.5 TPY. In Tables 2-3 and 2-5, the CO lb/hr short term emission rate for simple cycle operation at 59 degrees F is 20.3 lb/hr and 151.3 lb/hr for gas and oil, respectively. Twenty pounds per hour for 7760 hours on gas and 151.3 lb/hr for 1000 hours on oil equates to 154.5 TPY, which is a long term emission rate. For modeling purposes, the worst-case scenario should be used. Please use short-term emission rates for all pollutants with short-term averaging times.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department.......... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

We will forward any comments from EPA Region IV and the National Park Service as soon as they are received. If you have any questions regarding this matter, please contact Teresa Heron (review engineer) at 850/921-9529 or Debbie Nelson (meteorologist) at 850/921-8986.

Sincerely,

A.A. Linero, Program Administrator
Permitting South Section

AAL/th

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