Progress Energy

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BUREAU OF AIR REGULATION

September 29, 2006

053-9576

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

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   Date 9/26/06

(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 **7** days/week **52** weeks/year **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.)

Potential/Estimated Fugitive Emissions

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

1. Pollutant Emitted: **PM/PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **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	

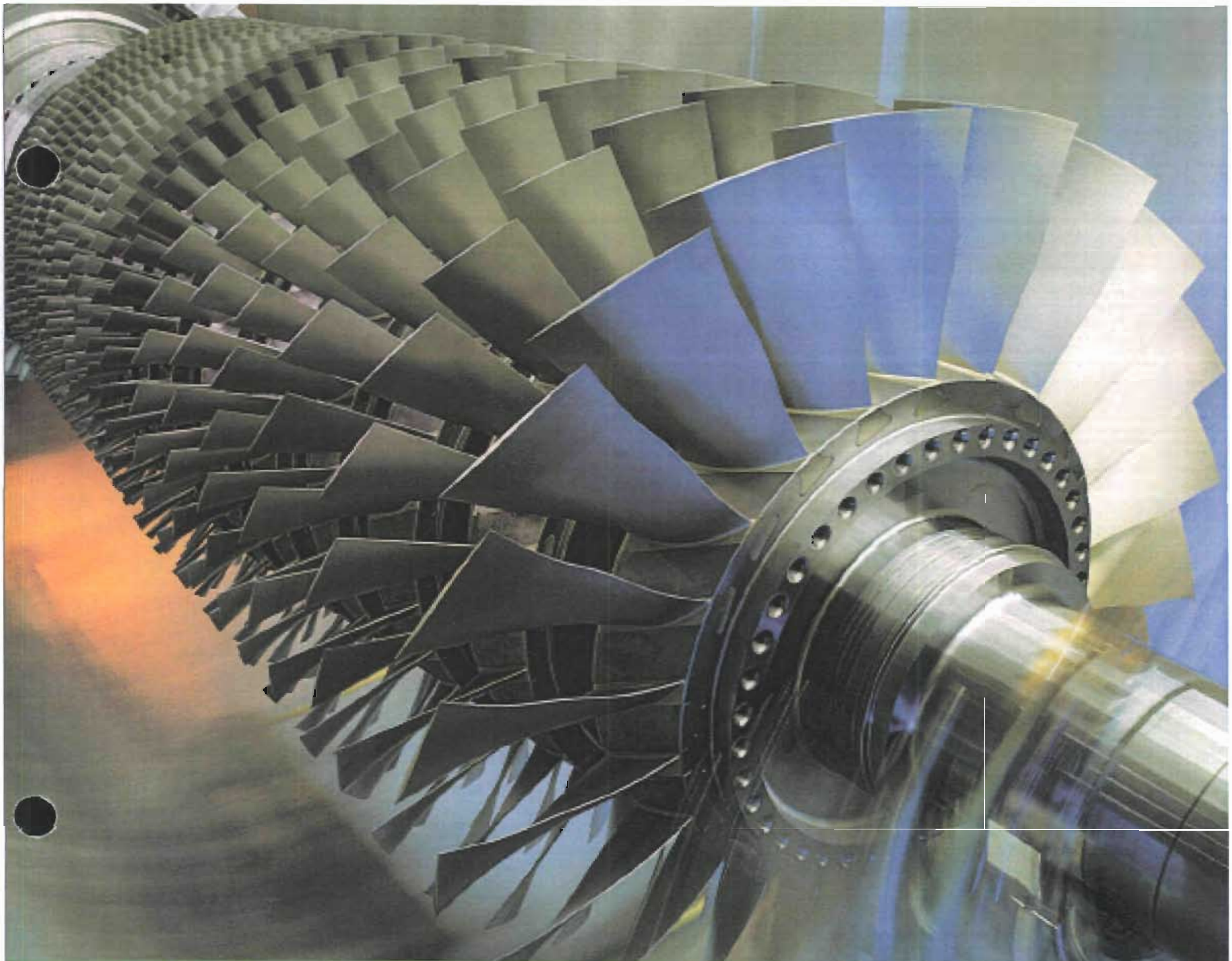
Additional Requirements for Title V Air Operation Permit Applications

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:

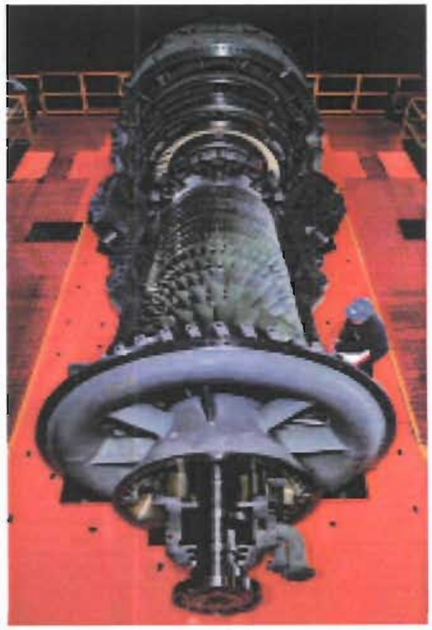
- Most powerful 60 Hertz F-class engine – capable of over 230 MW
- High simple and combined cycle efficiencies
- Single digit ppm NOx and CO capability
- Cyclic capability including daily start/stop – 10 minute start-up capability
- Hot re-start capability – without time delay
- Foremost maintainability – 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.

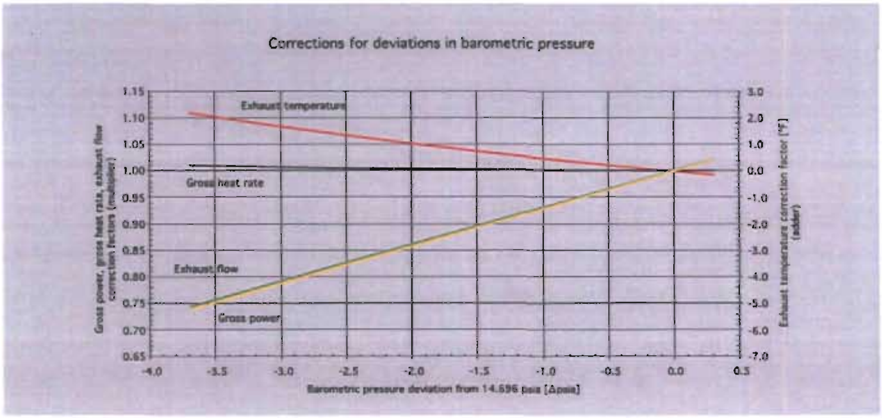
* *SPPA-3000 was formerly known as the TXP.*

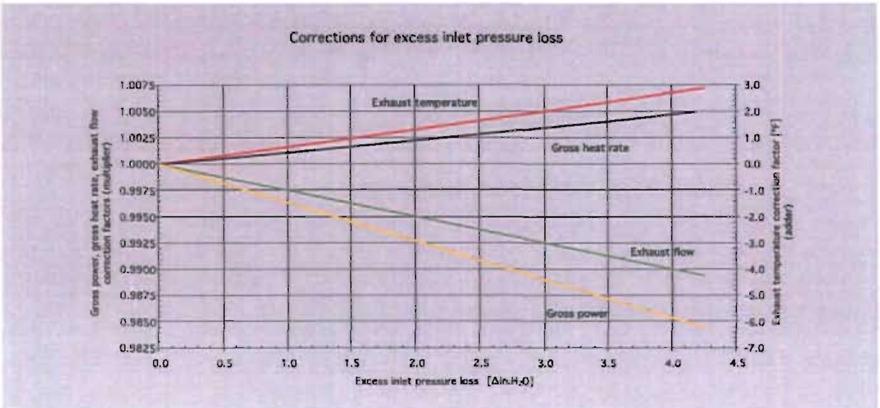
Net performance for the SGT6-PAC 5000F

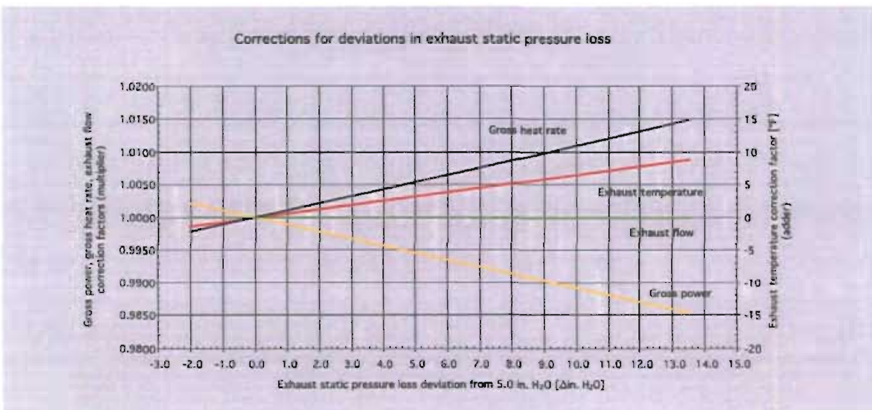
Power plant conditions: Natural gas or liquid fuel meeting Siemens Power Generation's fuel specifications, sea level, 60% relative humidity, 59°F (15°C) inlet air temperature, 3.4 in. water (87 mm water) inlet loss, 5 in. water (127 mm water) exhaust loss, air-cooled generator and .90 power factor (pf).

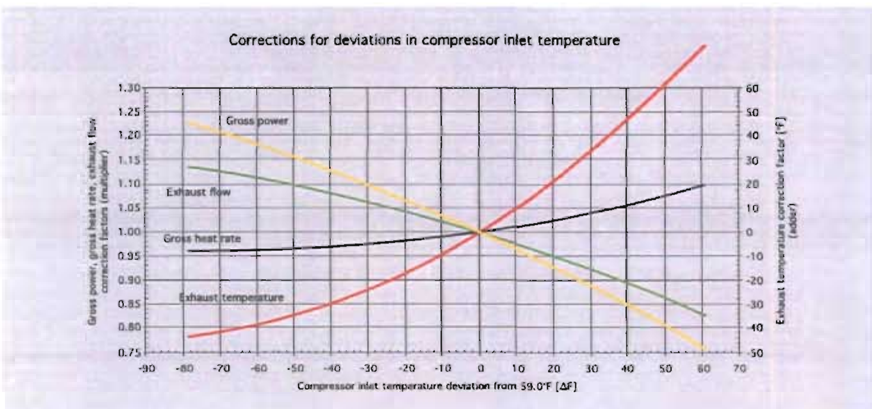
Combustor type	DLN dry	Conventional water injection	Conventional steam injection	DLN* steam augmentation
Fuel	**Natural gas**	**Natural gas**	**Natural gas**	**Natural gas**
Net power output (kW)	194,500	206,200	214,000	213,190
Net heat rate (Btu/kWh) (LHV)	9,087	9,471	8,763	8,870
Net heat rate (kJ/kWh) (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	4,068,000	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
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)
Barometric pressure deviation from 14.696 psia [Δpsia]


Corrections for excess inlet pressure loss
Exhaust temperature
Gross heat rate
Exhaust flow
Gross power
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)
Excess inlet pressure loss [Δin.H₂O]


Corrections for deviations in exhaust static pressure loss
Gross heat rate
Exhaust temperature
Exhaust flow
Gross power
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)
Exhaust static pressure loss deviation from 5.0 in. H₂O [Δin. H₂O]


Corrections for deviations in compressor inlet temperature
Gross power
Exhaust flow
Gross heat rate
Exhaust temperature
Gross power, gross heat rate, exhaust flow correction factors (multiplier)
Exhaust temperature correction factor [°F] (adder)
Compressor inlet temperature deviation from 59.0°F [ΔF]

Compressor wash package

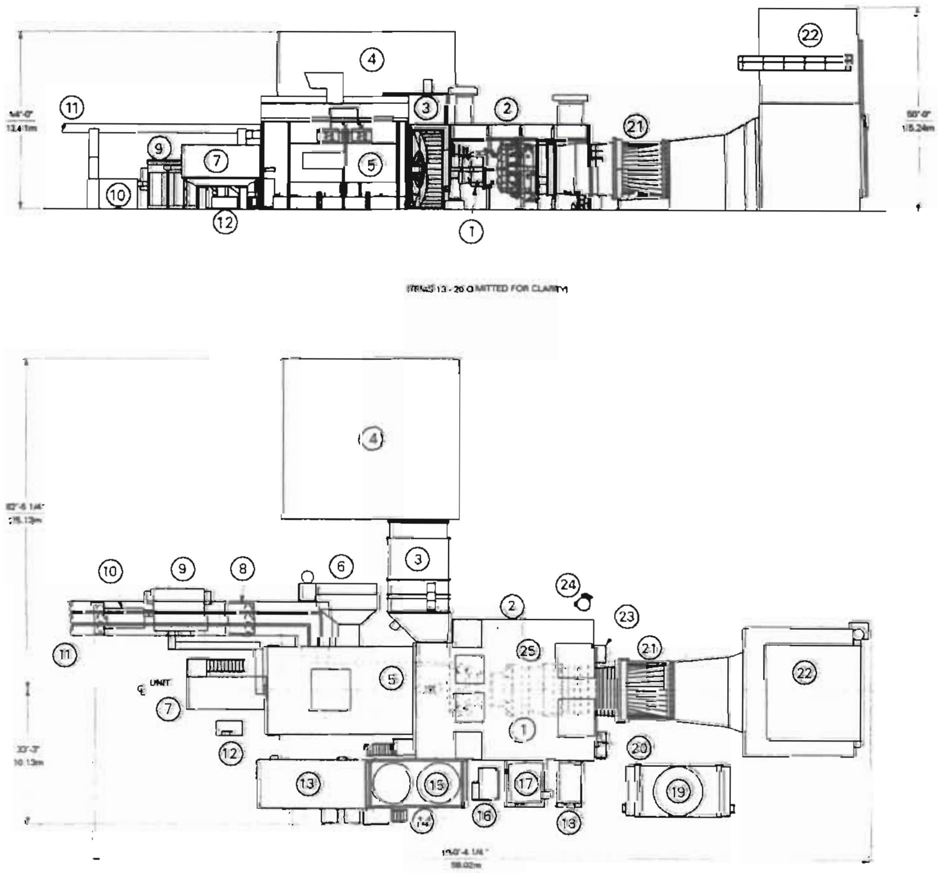
The compressor wash package is provided for both on-line and off-line compressor cleaning. This package accommodates the pump, eductor for detergent injection, piping, valving, orifices and detergent storage tank.

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

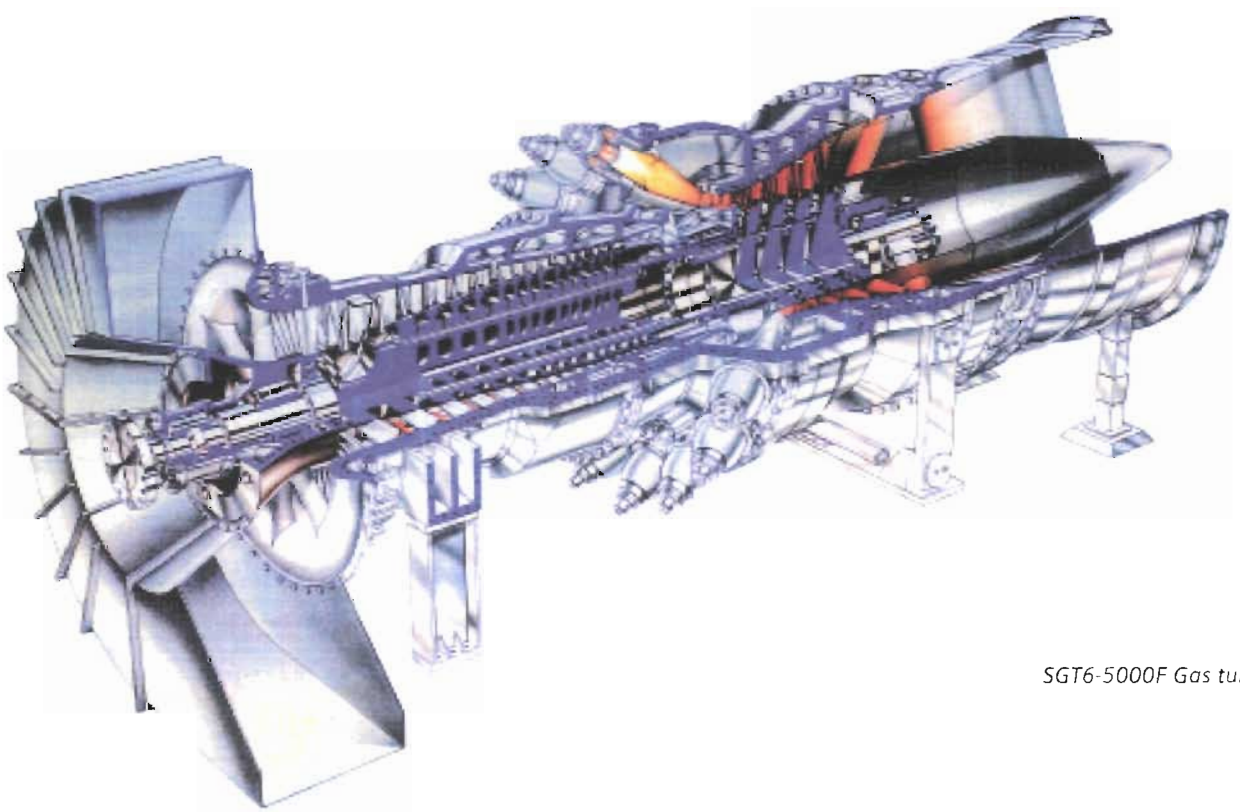
Generator

Type	— Standard	Open air-cooled
	— Option	Totally enclosed water-to-air cooled
	— Option	Hydrogen-cooled
Frequency		60 Hz
Voltage		15 kV
Insulation		Class F

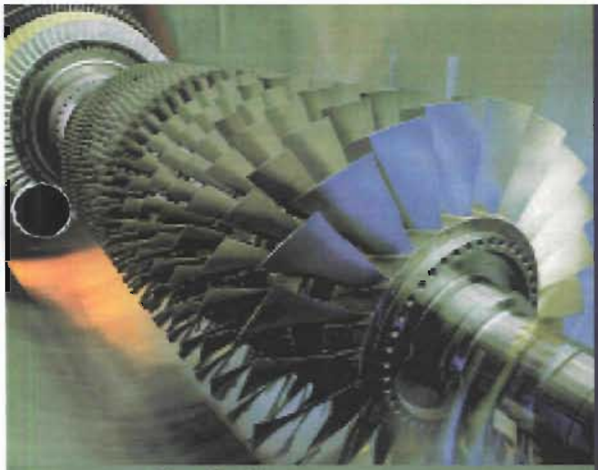
Major weights

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


Gas Turbines

Siemens AG
Power Generation
Freyeslebenstrasse 1
91058 Erlangen, Germany

Siemens Power Generation, Inc.
4400 Alafaya Trail
Orlando, FL 32826-2399, USA

e-mail: info.pg@siemens.com
www.siemens.com/powergeneration

Order No. A96001-W90-A240-X-4A00
Printed in USA
0806-COLMAM-WS-06051.

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	

ATTACHMENT 3

HINES ENERGY CENTER EMISSION TEST DATA

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. 4911

Prepared by

Cubix Corporation
http://www.cubixcorp.com

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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		
Date	1/1/99	1/1/99	1/1/99		
Start Time	9:05	13:21	14:58		FDEP
Stop Time	10:05	14:21	15:59		Permit
Turbine/Compressor Operation				*Averages*	Limits
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

Testing by Cubix Corporation - Austin, Texas - Gainesville, Florida

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

TABLE 6: Summary of Results
Reduced Load Testing
Unit 1B

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

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

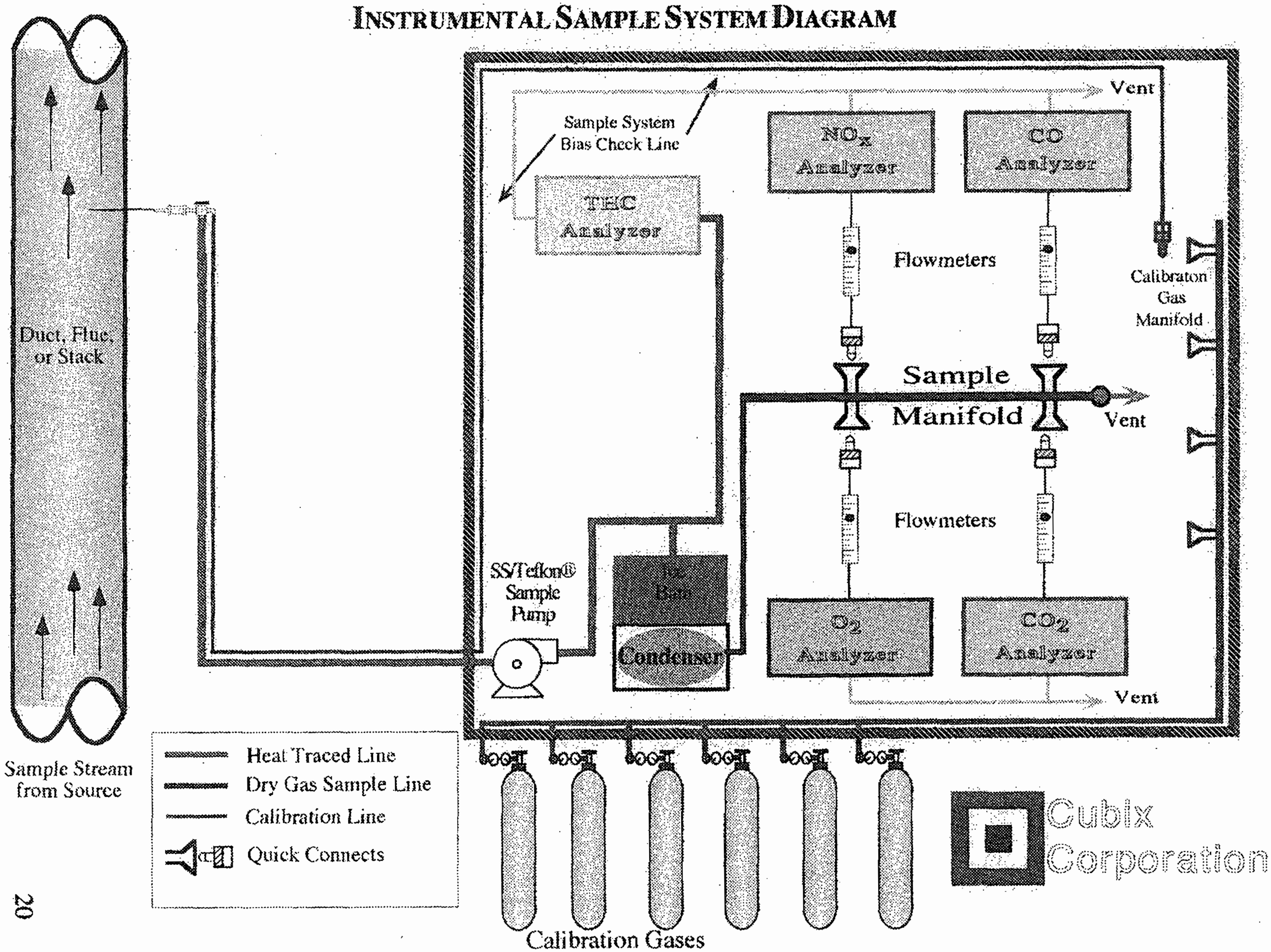
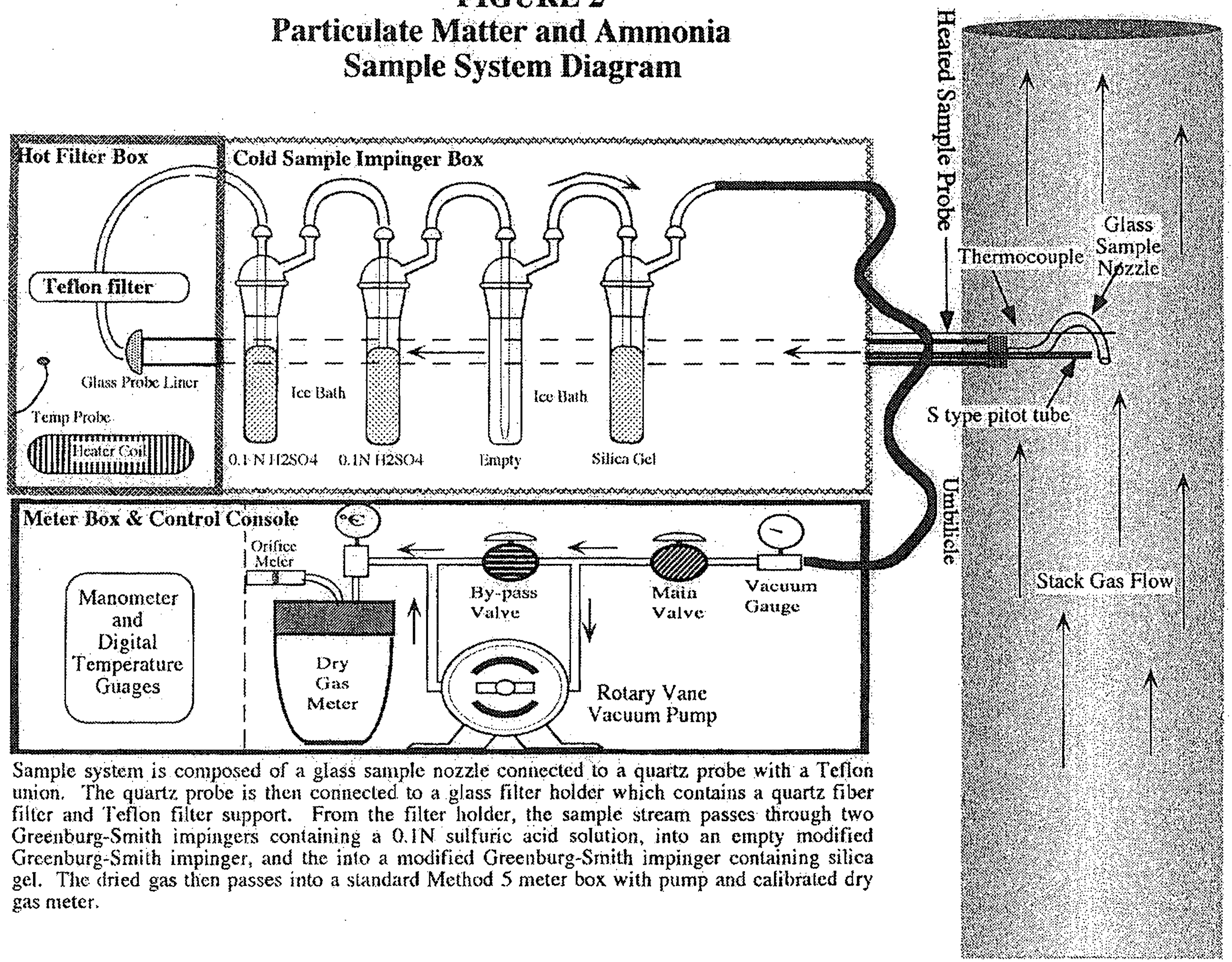


FIGURE 2
Particulate Matter and Ammonia Sample System Diagram



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.

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	Averages	FDEP Permit Limits
Date	4/11/99	4/11/99	4/11/99		
Start Time	18:28	20:14	22:28		
Stop Time (24 hour clock	19:28	21:20	23:28		
Power Turbine Operation					
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_2O (% volume)	7.50	7.95	9.34	*8.26*	
F_a (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		FDEP Permit Limits
Date	4/1/99	4/1/99	4/1/99		
Start Time	13:10	15:50	17:50		
Stop Time	14:10	16:50	18:50		
Power Turbine Operation				*Averages*	
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

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	0.254	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**

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, 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	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

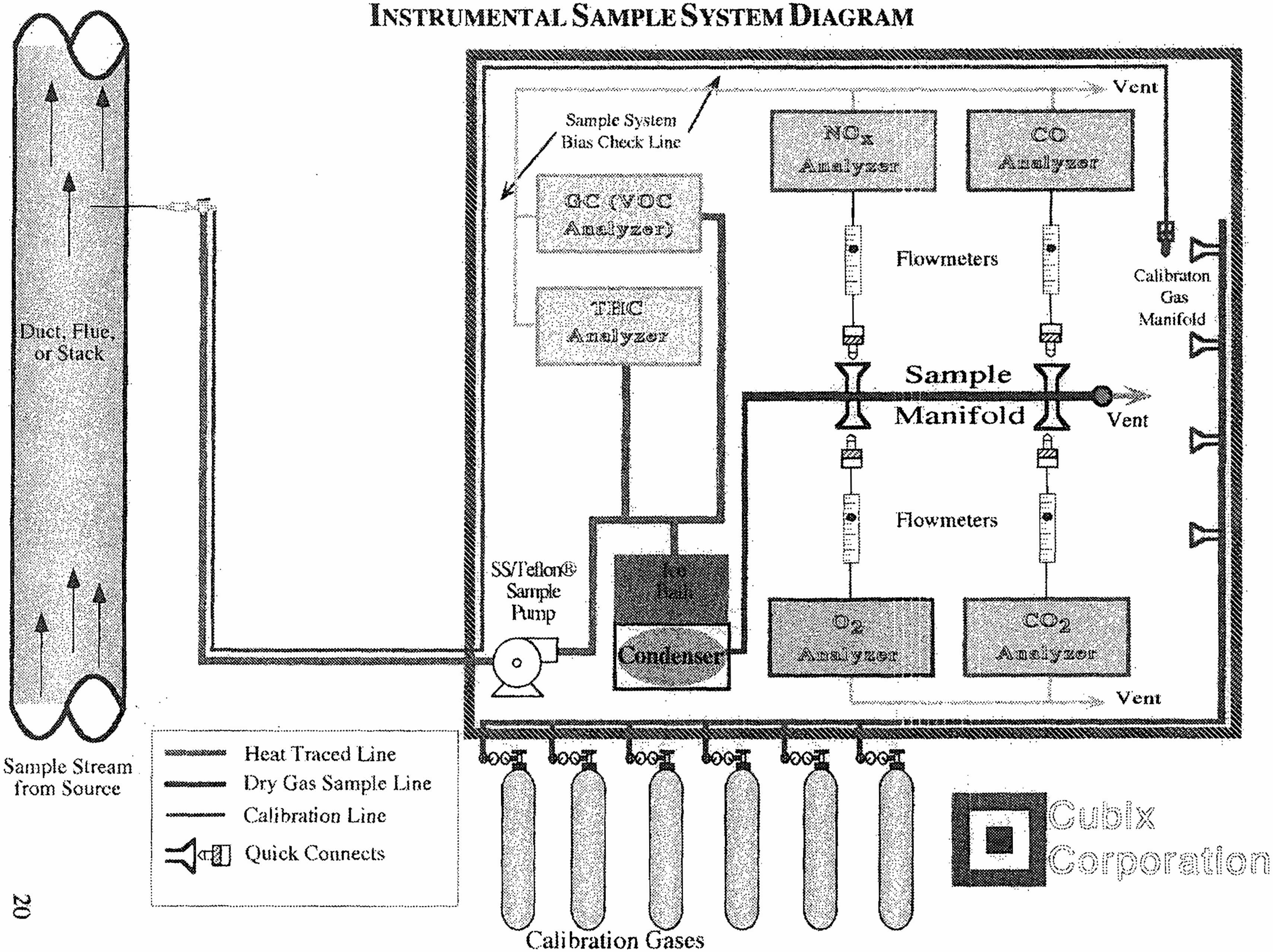
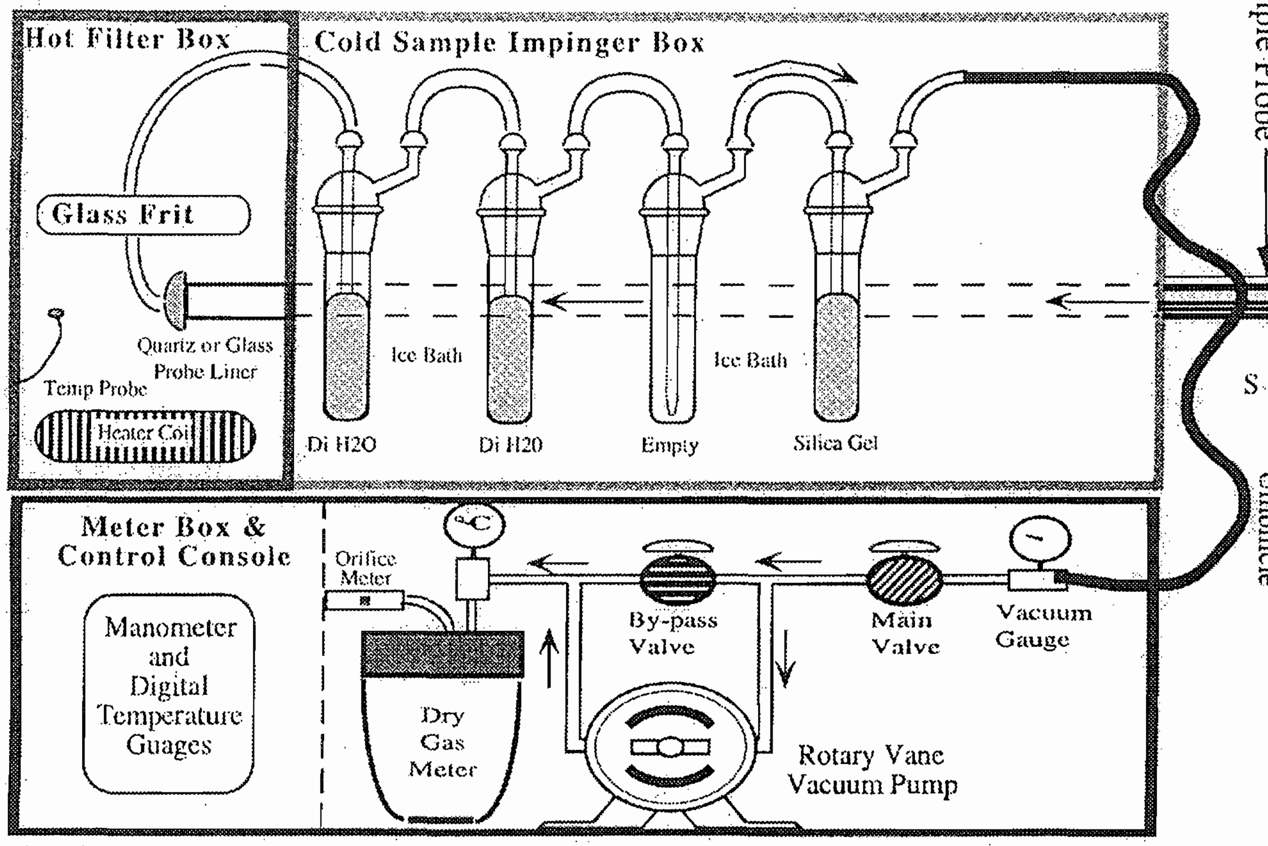
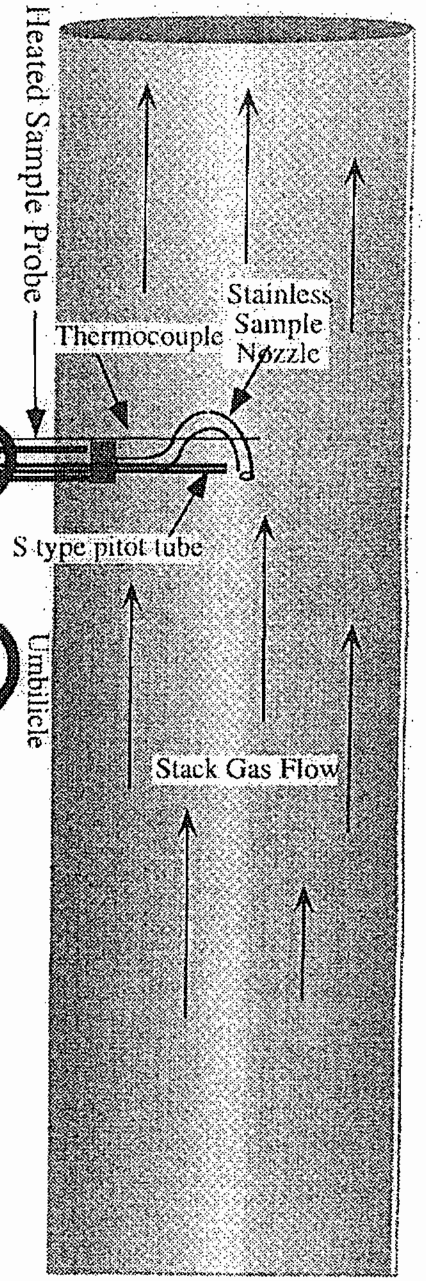


FIGURE 2
Particulate Matter Sample System Diagram





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.

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 $\geq 3\%$ 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:

$$\text{ppmd} = \frac{\text{ppmw}}{1 - B_{ws}}$$

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

NOTE

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

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)
Unit 2A - Natural Gas															
High (Base)	1	11/08/03	1034-1157	164.0	96.5	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															
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															
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															
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	12.66	13.86	10.59	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 (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/08/03	1034-1157	164.0	98.5	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	3.26	3.05	45.220	1280.4	3853	4.26	13.87	3.57
	AVERAGE			163.1	96.6	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 (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/07/03	1104-1229	168.2	98.8	1846.5	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	1828.9	196.5	3.28	3.10	44.236	1252.6	3088	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	3061	3.42	13.98	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 (µg)	NH3 Slip (ppm)	O2 (%d)	NH3 Slip (ppmd @ 15% O2)
High (Base)	1	11/12/03	0907-1007	160.0	94.1	1669.5	420.5	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 (µg)	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	1673.8	550.8	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 = 24.056
- 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	1831.8
	2	11/08/03	1210-1334	163.2	96.0	1761.3	17613.3	1036	1824.7
	3	11/08/03	1345-1518	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	165.6	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	-
18	200.62	83860	5350	89210	21039	1877	4
	102.25	43190	9480	52670	21039	1108	8
59	185.12	76820	4690	81510	21039	1715	1
	81.95	40160	8820	48980	21039	1030	16
103	156.15	67550	4310	71860	21039	1512	5
	77.39	36530	7880	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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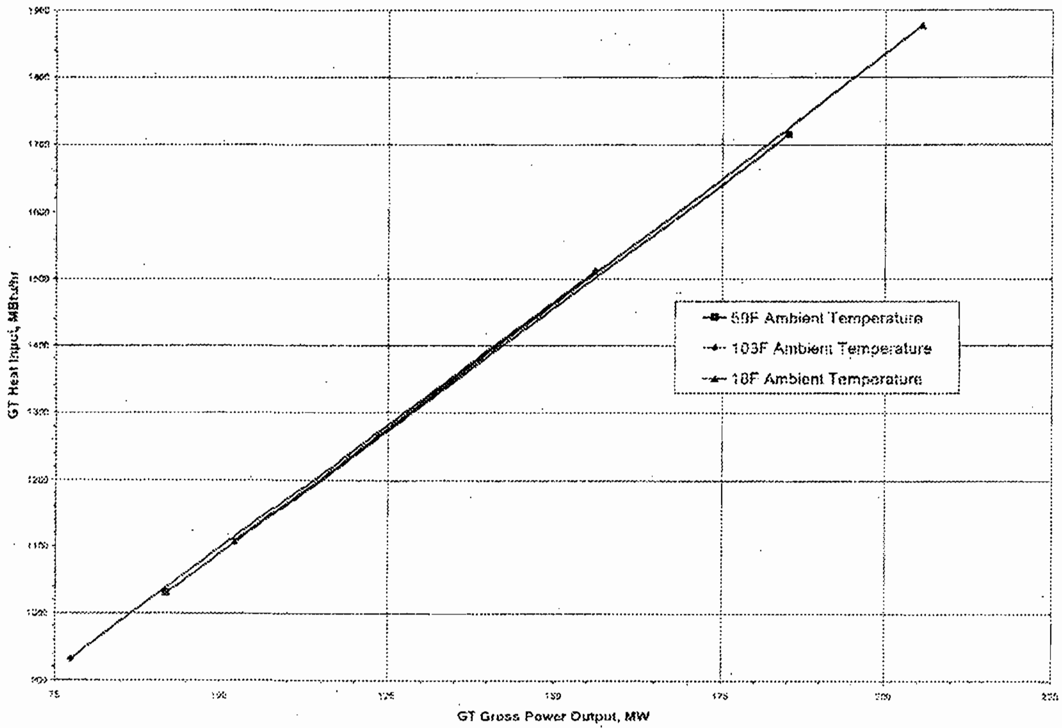

Progress Energy

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 Response[1]	Span-Level Response[2]	Performance Specification[3]
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[1]		
			@ 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

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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.

1

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 ≥ 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 $\geq$ 5% of span or, for drift checks, $\geq$ 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 ≥ 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	4.15	13.58	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**

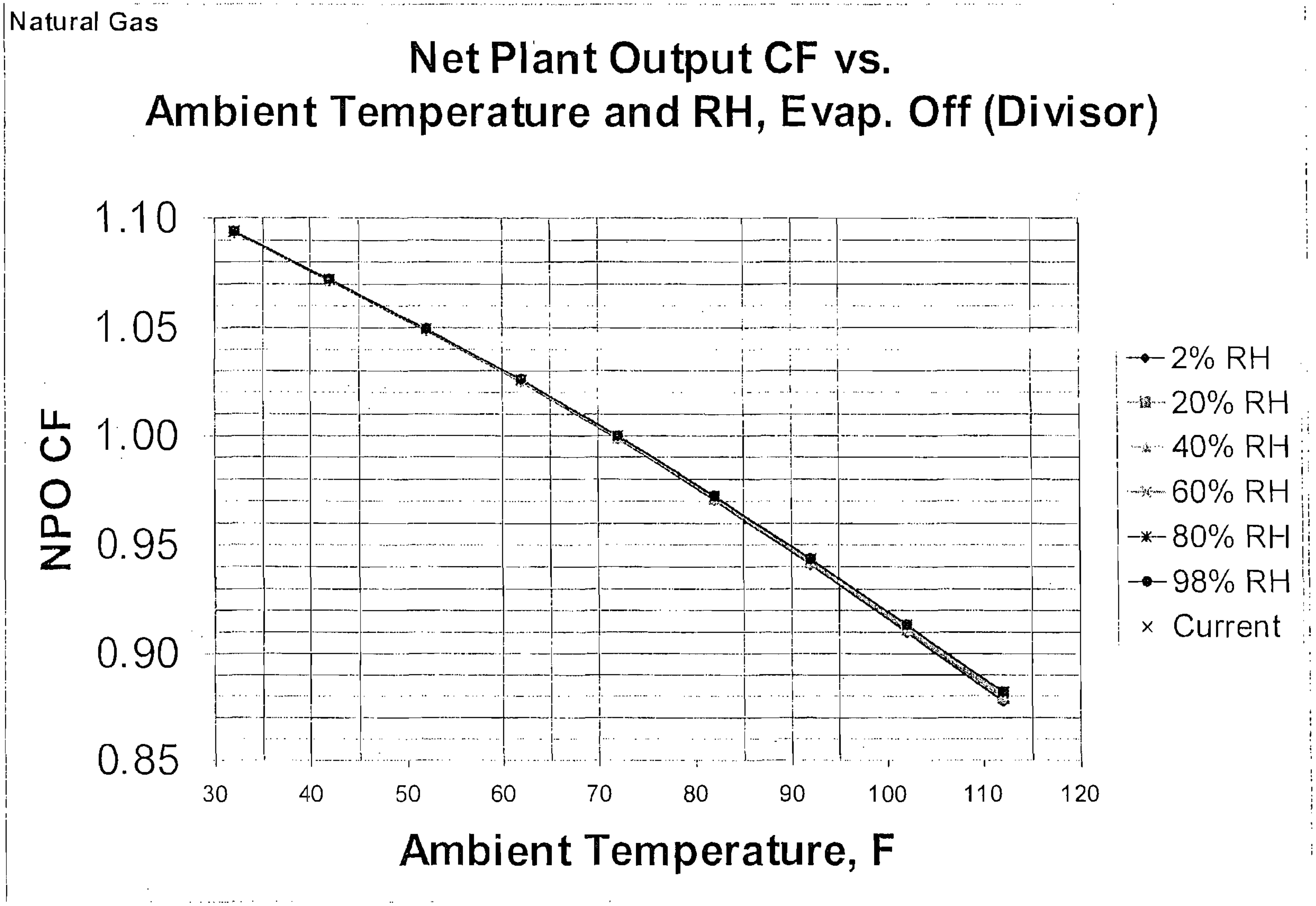
Unit 3B - No. 2 Fuel Oil

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**

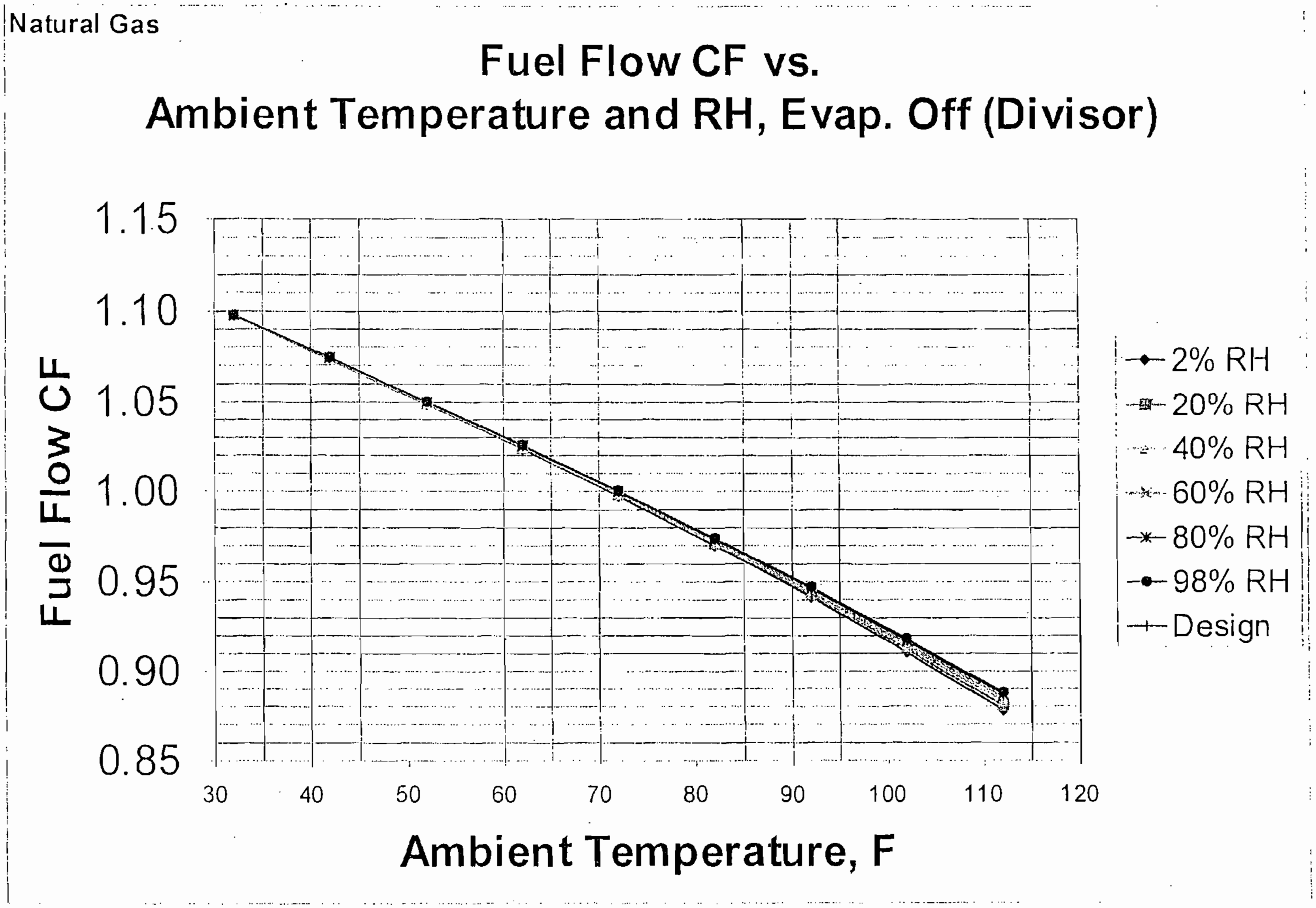
NOTES:

- 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

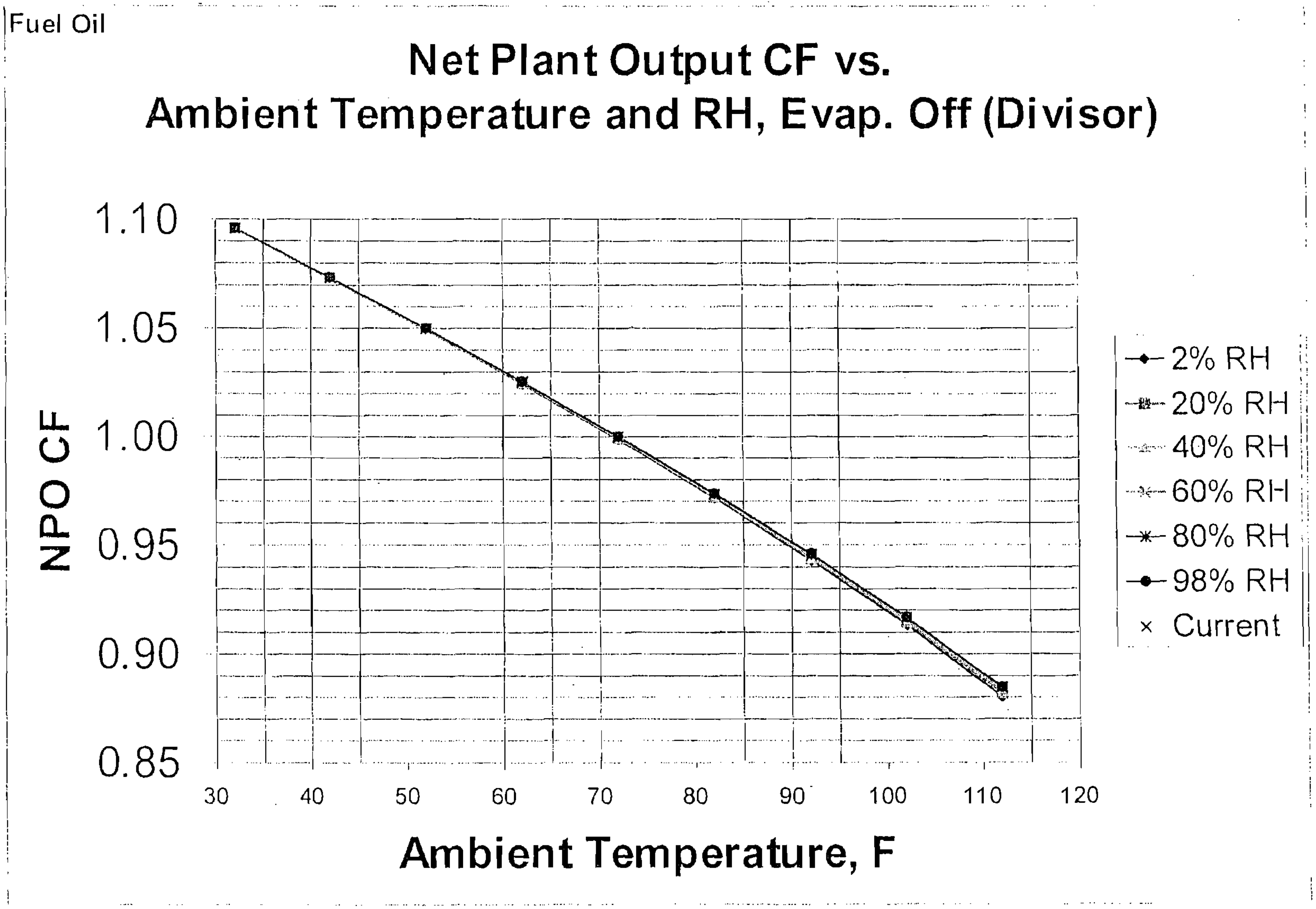
APPENDIX 8 – TURBINE MANUFACTURER PERFORMANCE CURVES

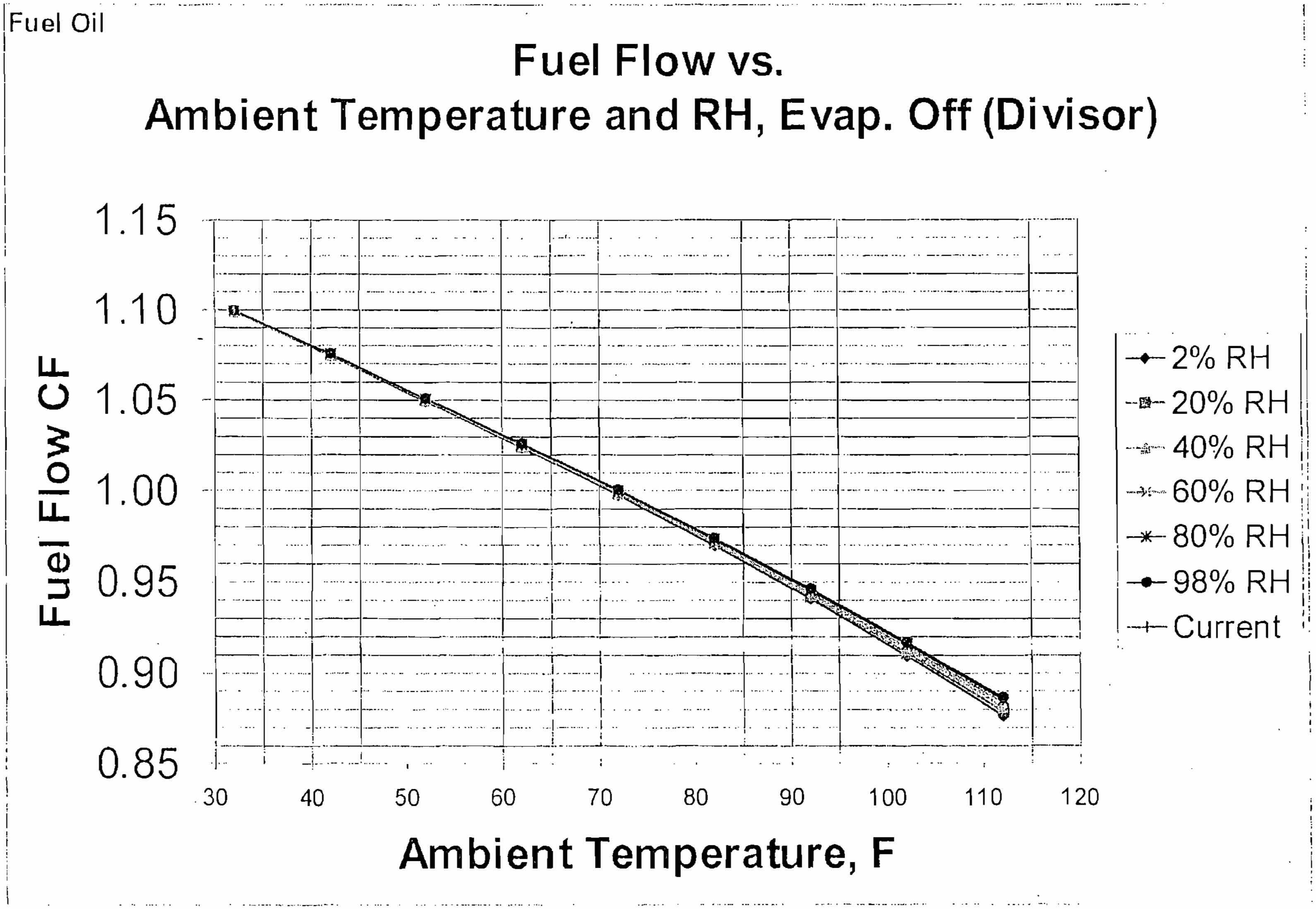


Natural Gas
Net Plant Output CF vs.
Ambient Temperature and RH, Evap. Off (Divisor)
NPO CF
1.10
1.05
1.00
0.95
0.90
0.85
30
40
50
60
70
80
90
100
110
120
Ambient Temperature, F
2% RH
20% RH
40% RH
60% RH
80% RH
98% RH
Current



Natural Gas
Fuel Flow CF vs.
Ambient Temperature and RH, Evap. Off (Divisor)
1.15
1.10
1.05
1.00
0.95
0.90
0.85
Fuel Flow 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
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

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

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

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 Minimum 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_20 Temperature - °F (°C).......... 200 (93)
Minimum Engine H_20 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)*

CLARKE

Fire Protection Products

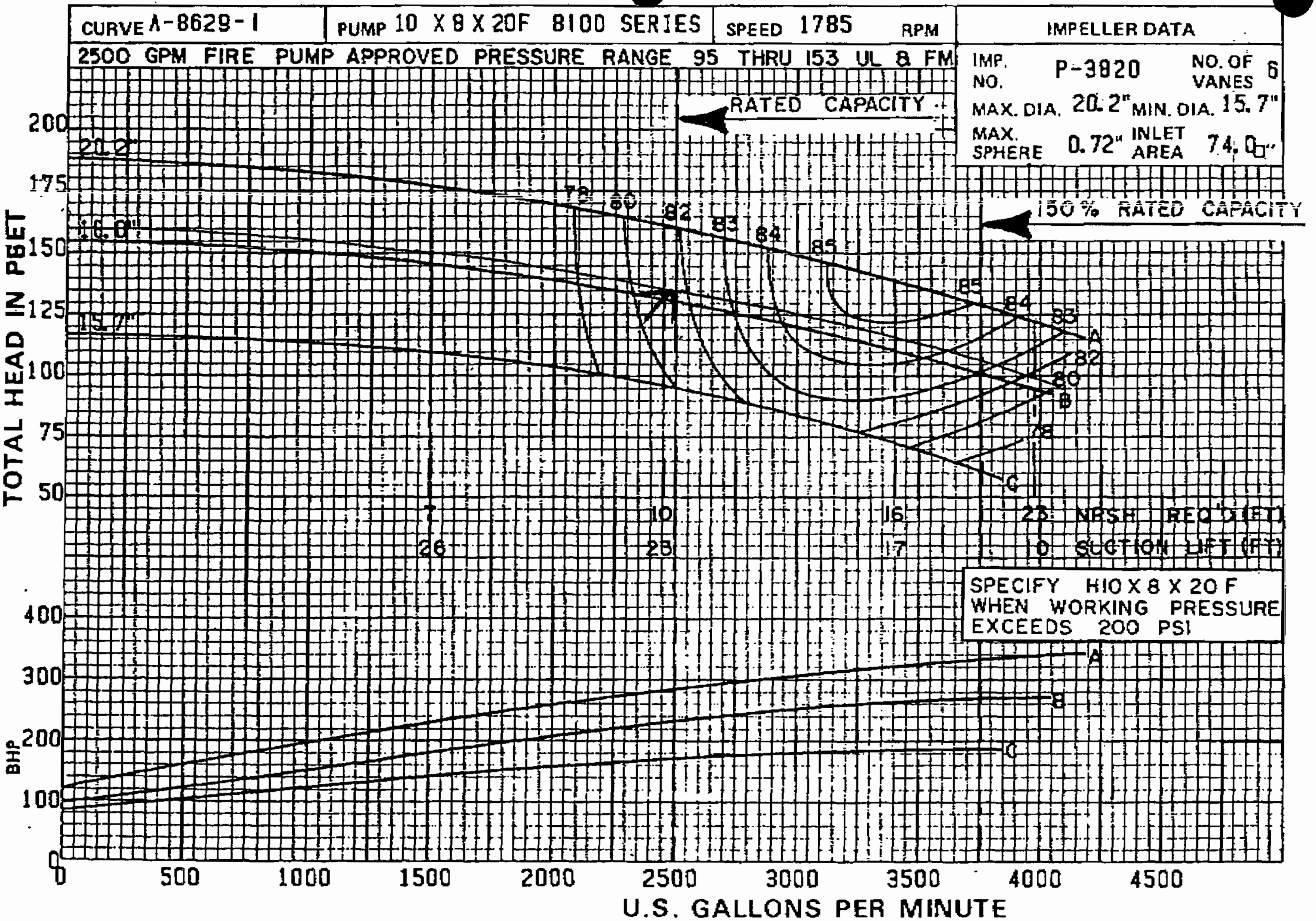
JW6H-UF58
INSTALLATION & OPERATION DATA (Continued)

	1760
Exhaust System	
Exhaust Flow - ft.^{3}/min. (m^3/min.)	1642 (46)
Exhaust Temperature - °F (°C)	866 (463)
Maximum Allowable Back Pressure - in. H_20 (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_20 (mH_20)	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_20 (kPa)	14 (3.5)
Clean Air Cleaner - in. H_20 (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



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

Plant ID	Facility Name	County	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative to the Bartow Plant[a] X (km)	Relative to the Bartow Plant[a] 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)	Relative to the Bartow Plant[a] Y (km)	Relative to the Bartow Plant[a] Direction (deg.)	Relative to the Bartow Plant[a] 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

AIRS No.	County	Location	Measurement Period Year	Measurement Period Months	Units	3-Hour Highest	3-Hour 2nd Highest	24-Hour Highest	24-Hour 2nd Highest	Annual 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

Pollutant	Averaging Time	Rank	Maximum Predicted Concentration (ug/m^3) Modeled Sources [a]	Background [c]	Total	Time Period (YYMMDDHH)	AAQS (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

Pollutant	Averaging Time	Rank	Maximum Predicted Concentration (ug/m^3) Phase 2 Only	PSD Sources	Time Period (YYMMDDHH)	PSD Class II Increment (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 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
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 Comhustor 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

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
	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	0.5	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	2AGRI	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	12AGRI	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)	Stack Height ft	Stack 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)	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.